Advanced Fossil Power Systems
Comparison Study

SUMMARY

Aspen Plus® (version 10.2) simulation models and the Cost of Electricity (COE) have been developed for advanced fossil power generation systems both with and without carbon dioxide (CO_2) capture. The intent was to compare the cycles based on using common assumptions and analytic standards with respect to realizable performance, cost, emissions and footprint. Additionally, commercially available (or near term) reference plants were included for comparison.

The advanced fossil power systems considered were: (both natural gas and coal fueled)

- Hydraulic Air Compression Cycle (HAC)
- Rocket Engine Gas Generator Cycle
- Hydrogen Turbine (air) Cycle
- Hybrid Cycle (Turbine / Solid-Oxide Fuel Cell)
- Humid Air Turbine Cycle (HAT) [(CO_2) capture – not considered]

Reference Plants developed based on previous NETL/EG&G studies included:

- Pulverized Coal (PC) Boiler
- Natural Gas Combined Cycle (NGCC)
- Integrated Gasification Combined Cycle (IGCC)

Capital cost estimates were developed for the above cases using data from the EG&G Cost Estimating Notebook (version 1.11) and several contractor reports. The format follows the guidelines set by EPRI TAG methods. Individual equipment sections were based on capacity factored techniques. The costs are reported in first quarter 2002 dollars. The total capital requirement includes equipment, labor, engineering fees, contingencies, interest during construction, startup costs, working capital and land. Other assumptions are provided in summary tables in Appendix B which contains the COE spreadsheets developed for all cases.

Results are compared in Table 1 (Natural Gas Cycles) and in Table 2 (Coal Cycles). These results demonstrate the following key observations:

- For all systems, (CO_2) capture entails major cost & efficiency penalties.
- Only Hybrids perform at or near the Vision 21 efficiency goals summarized in Appendix D.
- Rocket Engine cycles have lower efficiency and higher cost than other options requiring far less development.
- HAC cycles based on a closed-loop water system are unattractive. An open-loop water system (dam site) may be attractive as a niche market.
- Hydrogen Turbine (air) and HAT cycles are also unattractive.

TABLE 1 - Natural Gas Cycles

POWER SYSTEM	NATURAL GAS COMBINED CYCLE (NGCC)		HYDRAULIC AIR COMPRESSION (HAC)		ROCKET ENGINE (CES)	HYDROGEN TURBINE (HT)	Hybrid Cycle	HUMID AIR TURBINE (HAT)
Power Generation Cycle	NGCC "G" Gas Turbine	NGCC "G" Gas Turbine (CO2 Capture)	HAC NATURAL GAS	HAC NATUTAL GAS (CO2 CAPTURE)	CES (gas generator) (CO2 CAPTURE)	HT (H2 FROM SMR) (CO2 CAPTURE)	Hybrid Turbine (Siemens/West.) -SOFC / Turbine	HAT (PW GT) Natural Gas
Net Power MWe	379.1	326.9	323.5	300.2	398.4	413.1	19	318.7
Net Plant Efficiency	57.9	49.9	53.2	43.8	48.3	64.4 (H_2)	67.3	57.6
% LHV						42.9 (NG)		
Total Capital Requirement	515	911	681	1140	975	1323	1476	873
$ / KW								
Cost of Electricity	34.7	48.3	44.2	61.0	49.2	63.5	53.4	47
$ / MW-hr								
NOx emissions	0.176	0.204	0.194	0.210	NEG	0.161	0.0132	0.074
lb/MW-hr								
Sox emissions	---	---	---	---	---	---	---	---
lb/MW-hr								
CO2 Production								
lb/MW-hr								
a) Emitted to atmosphere	757	88	824	100		*	661	758
b) Sequesterable		790		899	901	719		
Footprint (battery limits)	282	362	179	230	825	472	1120	175
sq ft/MW								

Table 2 - Coal Cycles

POWER SYSTEM	PULVERIZED COAL (PC)			INTEGRATED GASIFICATION COMBINED CYCLE (IGCC)				
Generation Cycle	PC Steam Cycle (no CO2 Capture)	PC Steam Cycle (amine CO2 Capture	PC Steam Cycle (O2 Boiler/ CO2 CAPTURE)	IGCC Destec (E-Gas) CGCU "G" Gas Turbine	IGCC Destec (E-Gas) HGCU "G" Gas Turbine	IGCC Destec (E-Gas) CGCU "G" Gas Turbine (CO2 Capture)	IGCC SHELL CGCU "G" Gas Turbine	IGCC SHELL CGCU Gas Turb (ANL) (CO2 Capture)
Net Power MWe	396.8	283	298.4	400.6	400.4	358.6	412.8	351.1
Net Plant Efficiency	38.9	27.7	30.5	46.7	49.4	40.1	47.4	40.1
% LHV								
Total Capital Requirement	1268	2373	2259	1374	1354	1897	1370	2270
$ / KW								
Cost of Electricity	42.3	76.6	68.8	40.9	39.1	54.4	40.6	62.9
$ / MW-hr								
NOx emissions	4.09	5.74	0.27	0.165	0.165	0.185	0.160	0.182
lb/MW-hr								
Sox emissions	3.12	4.38	3.97	0.342	0.04	0.113	0.276	0.112
lb/MW-hr								
CO2 Production								
lb/MW-hr								
a) Emitted to atmosphere	1837	129	*	1517	1431	231	1496	190
b) Sequesterable		2448	2332			1536		1569
Footprint (battery limits)	636	1009	1591	1092	1057	1198	1065	1168**
sq ft/MW								

Table 2 - Coal Cycles (continued)

POWER SYSTEM	HYDRAULIC AIR COMPRESSION (HAC)		ROCKET ENGINE (CES)	HYDROGEN TURBINE (HT)	HYBRID CYCLE (HYB)			HUMID AIR TURBINE (HAT)
Generation Cycle	HAC Destec (E-Gas) CGCU	HAC Destec HP (E-Gas) HGCU (CO2 CAPTURE)	CES (gas generator) Destec HP (E-Gas) HGCU (CO2 CAPTURE)	HT Destec HP (E-Gas) HGCU (CO2 CAPTURE)	HYB Destec (E-Gas) HGCU "G" GT / SOFC (NO CO2 CAPTURE)	HYB Destec HP (E-Gas) HGCU/HSD "G" GT / SOFC (CO2 CAPTURE)	HYB Destec (E-Gas) OTM / CGCU "G" GT / SOFC (NO CO2 CAPTURE)	HAT (PW GT) Destec (E-Gas) CGCU
Net Power MWe	325.9	312.4	406.2	375.3	643.6	754.6	675.2	407.4
Net Plant Efficiency	43.8	35.2	41.4	38	56.4	49.7	57	44.9
% LHV								
Total Capital Requirement	1436	2189	1768	1909	1508	1822	1340	1411
$ / KW								
Cost of Electricity	47.0	65.5	49.3	53.6	41.1	48.8	38	42.1
$ / MW-hr								
NOx emissions	0.193	0.204	NEG	0.177	0.107	0.093	0.101	0.071
lb/MW-hr								
Sox emissions	0.337	0.048	0.044	0.046	0.005	0.004	0.014	0.353
lb/MW-hr								
CO2 Production								
lb/MW-hr								
a) Emitted to atmosphere	1561	142		131	1254	101	1237	1576
b) Sequesterable		1870	1702	1731		1323		
Footprint (battery limits)	1293	1583	1458	1445	1310	1408	1388	811
sq ft/MW								

I. REFERENCE PLANTS

I-1 PULVERIZED COAL (PC) BOILER

PC Boiler power plants without CO_2 capture represent a large number of the existing coal-fired power plants used for generating electrical power in the United States and North America. Three cases were developed based on previous Aspen Plus® simulations [1] for use as reference plants to contrast performance and cost with proposed advanced fossil power systems. The first case (Base Case) represents a modern power plant that employs both particulate and sulfur recovery. The remaining two cases are variations that add the possibility of CO_2 capture. The Base Case is an air-blown 400 MWe power plant without CO_2 capture that is used to establish baseline power plant performance and to assess the cost of electricity (COE). In the second case, an amine absorption process is added to capture CO_2 from the flue gas. The third case replaces the air used in the PC base case with a mixture of oxygen and recycled flue gas as the oxidant stream sent to the PC Boiler. This results in a flue gas stream containing primarily CO_2 and water vapor. Water is separated by condensation from the flue gas portion that is not recycled to obtain a concentrated CO_2 stream for sequestration. In both cases that capture CO_2, the CO_2 - rich stream was compressed to 1500 psia and leaves as a high pressure gas stream. (Further compression to approximately 2100 psia would be required to obtain a liquid stream. This would lower the process efficiency and raise the COE somewhat compared to the values listed in this report).

For the two cases with CO_2 capture, the boiler capacity was chosen the same as the base case to maintain the steam generation at the same amount. Any power or steam required for the CO_2 capture or the cryogenic oxygen plant was imported internally from the power plant. As a result, the net power production was reduced. It should be stressed that PC Boiler plants with CO_2 capture as described in these two cases are technically possible but are not currently existing commercial units due to both efficiency and cost penalties.

I-1.1 PC Power Plant - Base Case – Description

The Base Case consists of a power plant based on a pulverized coal (PC) boiler and steam turbine. The system described in a report by Buchanan et al. [2] was used as a design basis. This case was evaluated for benchmarking the performance of the other cases. A single reheat steam power cycle (2400psig/1000 ^oF /1000 ^oF) was used to generate 400 MWe of power. The steam generator was a natural circulation, wall-fired, subcritical unit arranged with a water-cooled dry-bottom furnace, superheater, reheater, economizer and air heater. The burners were low-NOx type. The flue gas was desulfurized by scrubbing with lime slurry. A simplified flow diagram is shown in Figure 1.

In this process, air is preheated in an air heater by exchanging heat with the flue gas. Coal and hot air are fed to the boiler from the bottom. High pressure steam is generated in the radiant section. Flue gas from the radiant section enters the convective section at 2200 ^oF. In the convective section, thermal energy from the flue gas is transferred to high-pressure steam, intermediate pressure steam and feed water. Flue gas leaves the convective section at 600 ^oF and passes through the air heater to preheat air. A precipitator is used to remove particulates and the flue gas is then sent to a SO_2 scrubber with the aid of an induced draft fan. Lime slurry is employed to scrub SO_2 from the flue gas. The cleaned flue gas leaves through the stacks. The high-pressure steam is superheated in the convective section. Superheated steam at 2415 psia and 1000 ^oF is expanded in the high-pressure turbine to an intermediate pressure of 604 psia. This IP steam is reheated in the convective section to 1000 ^oF and is then expanded in the IP steam turbine. Finally, the exhaust from the IP steam turbine is expanded in the LP (low pressure) turbine to 1 psia and enters the condenser. The condensate water is sent to a series of low-pressure feed heaters. The heated water is sent to the deaerator to remove dissolved gases. Deaerated water is passed through the high-pressure water heaters and is then fed to the economizer portion of the boiler's convective section. Water is further heated to close to its saturation temperature in the economizer and then sent to radiant section for boiling.

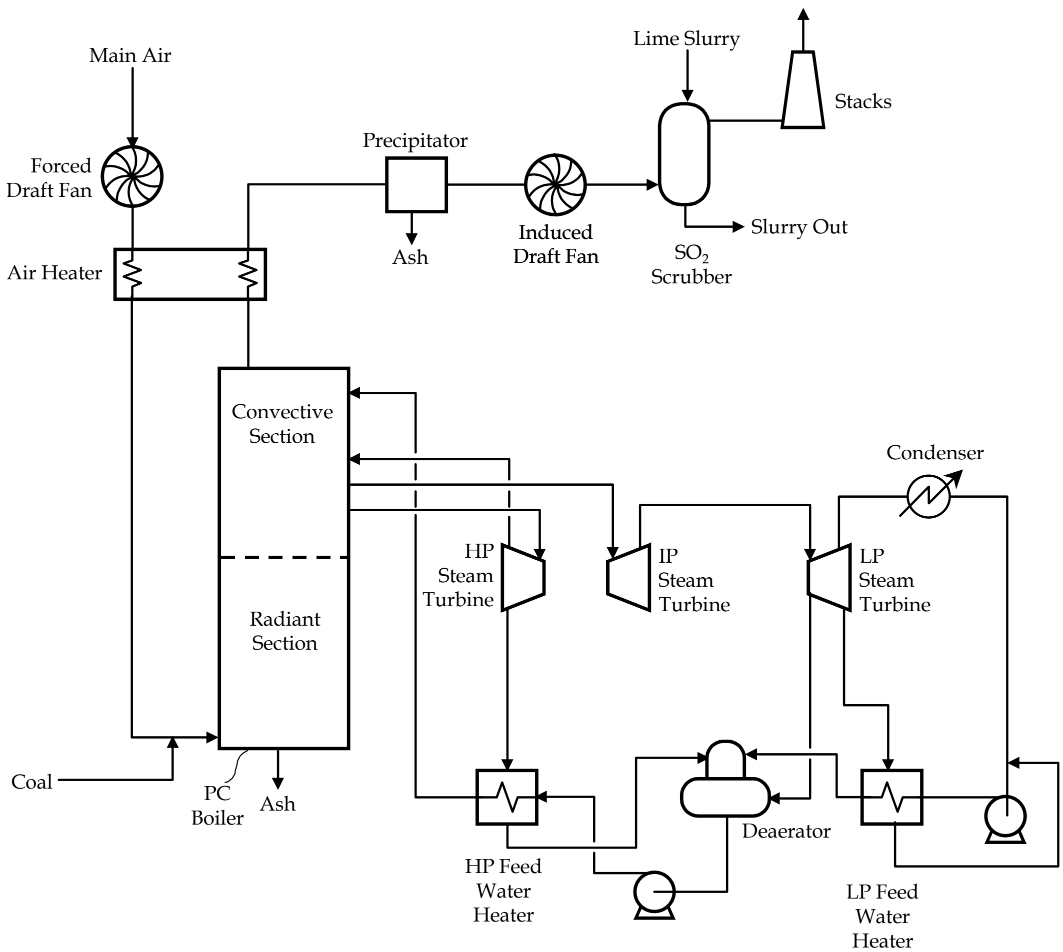

Figure 1. Pulverized Coal Boiler Power Plant

I-1.2 PC Power Plant - Amine CO_2 Capture – Description

In this case, the boiler operation is identical to the base case; i.e. air is used as the oxidant. The flue gas after sulfur removal is sent to an amine plant for CO_2 separation. In the amine plant, a MEA based solution is used to absorb CO_2 from the flue gas. The CO_2-depleted gas from the absorber is vented to the atmosphere. The CO_2-rich solvent is heated by lean solvent and then sent to a stripper for regeneration. Low-pressure steam (35 psia) is extracted from the LP turbine section and sent to the stripper reboiler of the amine plant. A concentrated CO_2 stream is recovered from the stripper and the lean solvent is recycled to the absorber. The CO_2 stream is compressed to1500 psia in a multistage intercooled compression section and leaves as a high pressure gas. The condensed water from the stripper reboiler is sent back to the steam cycle. Extraction of steam reduces significantly the gross power output from the steam turbines. Additionally, the amine plant consumes power for the flue gas blower and for the amine solvent recirculation pumps and a large power consumption is due to the required CO_2 compressor.

A simplified flow diagram is shown in Figure 2.

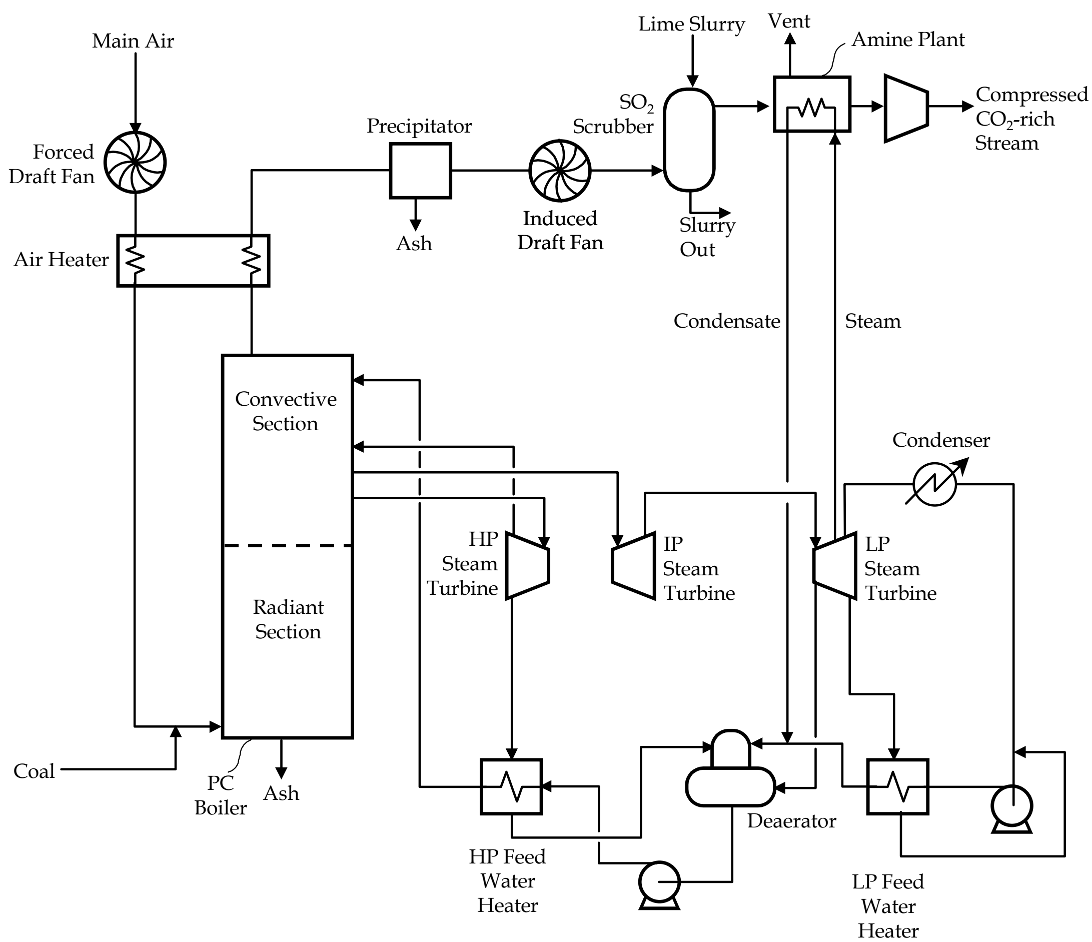

Figure 2. PC-Fired Boiler with Amine Scrubbing for CO_2 Sequestration

I-1.3 PC Power Plant – Cryogenic ASU – Description

A cryogenic ASU supplies oxygen to the PC fired boiler. Oxygen with 95% purity was selected, because the cost of oxygen is significantly lower than that for high-purity oxygen (>99.5% purity). A portion of the flue gas is recycled and mixed with oxygen from the cryogenic ASU. The resulting oxidant stream (mixture of O_2, CO_2 and H_2O and small amounts of Ar and N_2) is preheated in the inlet heater and fed to the boiler along with pulverized coal. Since most of the nitrogen from air is eliminated in the ASU, the flue gas leaving the boiler essentially contains CO_2 and water vapor. After the flue gas preheats the oxidant stream, it passes through a precipitator and the portion that is not recycled enters the SO_2 scrubber. Water is condensed out of the flue gas stream exiting the scrubber and a concentrated CO_2 stream is obtained. The CO_2-rich stream is compressed to 1500 psia for sequestration.

This case was iterated by adjusting flue gas recycle flow, oxygen flow and coal flow. The goal was to achieve the same temperatures for flue gas leaving the radiant and convective sections as those in the base case and to generate the same amount of steam from the boiler as the base case. Overall, the power generated from steam turbines was roughly the same as in the base case. However, a significant portion of the power is supplied to the ASU and the CO_2 compressor. A simplified flow diagram is shown in Figure 3.

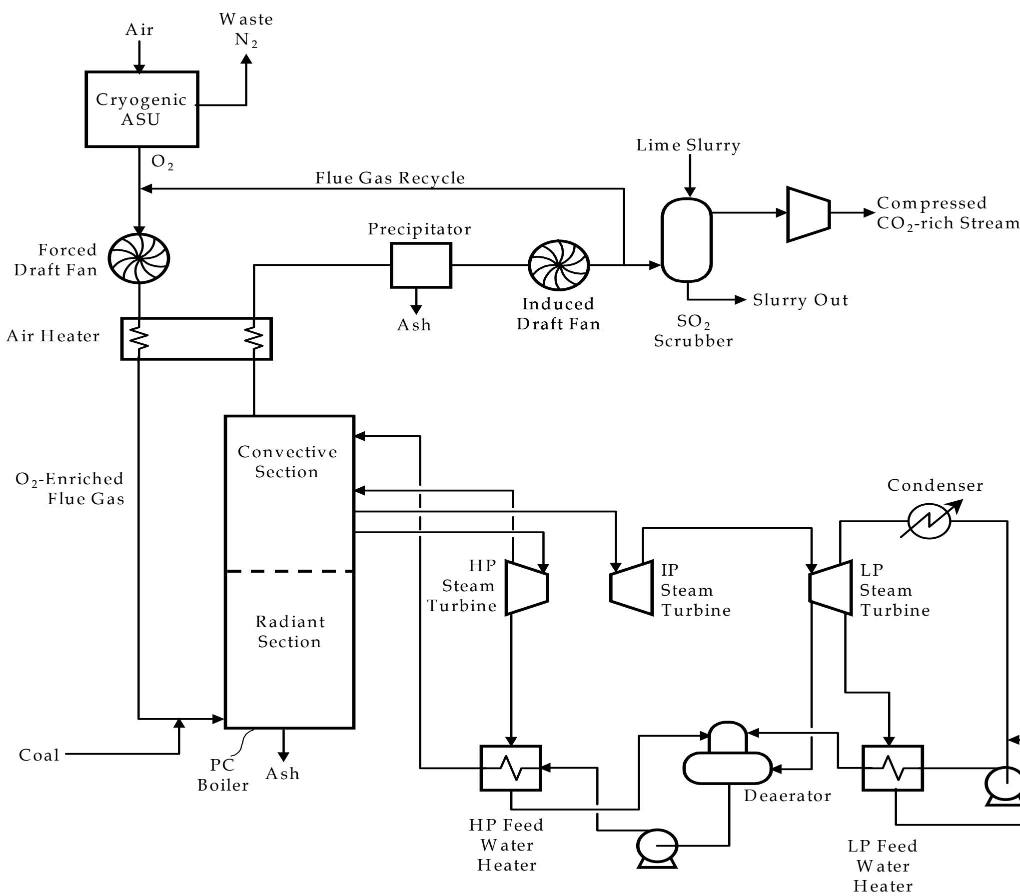

Figure 3. PC Fired Boiler with Flue Gas Recycle for CO_2 Sequestration; O_2 from Cryogenic ASU

I-1.4 PC Power Plant Results

Detailed flow diagrams with stream summaries are provided in Appendix A based on the Aspen Plus® simulation results. Emissions for NOx and SOx were based on the BACT (best available control technology) and CO_2 was based on simulation results. Capital cost estimates were developed based on Buchanan et al. [2] and vendor estimates for the amine plant and the oxygen plant [3]. Spreadsheets showing capital costs and the COE analysis are provided in Appendix B. The results shown below for these cases illustrate significant cost and efficiency penalties for CO_2 capture.

Table 3. Pulverized Coal (PC)

POWER SYSTEM	PULVERIZED COAL (PC)		
Generation Cycle	Coal PC Steam Cycle (no CO2 Capture)	Coal PC Steam Cycle (amine CO2 Capture	Coal PC Steam Cycle (O2 Boiler/ CO2 CAPTURE)
Net Power MWe	396.8	283	298.4
Net Plant Efficiency	38.86	27.72	30.5
% LHV			
Total Capital Requirement	1268	2373	2259
$ / KW			
Cost of Electricity	42.3	76.6	68.8
Constant $ / MW-hr			
NOx emissions	4.09	5.74	0.205
lb/MW-hr			
Sox emissions	3.12	4.16	2.98
lb/MW-hr			
CO2 Production			
lb/MW-hr			
a) Emitted to atmosphere	1837	129	*
b) Sequesterable		2448	2332
CO2 concentration (mole%)		99.70%	86.60%
(in sequestered gas)			
Footprint (battery limits)	636	1009	1591
sq ft/MW			

The Base Case power plant generates 396.8 MW and its efficiency is 38.9% (LHV) or 37.5% (HHV). The CO_2 capture decreases the efficiency by a dramatic 8 – 11 percentage points and and nearly doubles the base case's total capital requirement of $1268/KW.

The cost and performance of the amine plant are based on commercially available oxygen-tolerant amine technology designed to capture 95% of the CO_2. The energy consumption for the amine case was assumed to be 3.7 MMBtu / ton CO_2 recovered. (NETL is currently funding research aimed at reducing this by up to 50% , [4]). Steam consumption for regenerating the amine solution resulted in a significant penalty on power production. The power output from the steam turbine decreased to 325 MW. The consumption of power by the amine plant and the CO_2 compressor reduced the net power output from the power plant to 283 MW. Thus, 114 MW power was consumed for the CO_2 capture system. Overall efficiency of the system was 27.7% (LHV). Based on vendor information, the amine plant and CO_2 compression added $122 MM in capital cost to the base case. This increased the COE from 42.3 to 76.6 ($/MW-hr, Constant $ basis).

In the last case, PC oxygen/recycle flue gas boiler, it was assumed that the concentrated CO_2 stream can be sequestered without further processing. Thus, the entire CO_2-rich flue gas stream (not recycled) was compressed to 1500 psia for sequestration and there were no CO_2 emissions in this case. The cryogenic ASU produced 7570 tpd oxygen (on pure basis) of 95% purity (by vol.) and consumed 64 MW power. The compression of the CO_2-rich stream consumed another 34 MW. Use of oxygen increased the boiler efficiency as evidenced by reduced coal consumption. However, the net power output for the cryogenic case decreased to 298 MW and the efficiency decreased to 29.5%. Additional capital cost of $145 MM included the cost of the cryogenic ASU, the cost of redesigning the normal PC boiler for oxygen firing and the capital cost of the CO_2 compressor. The COE with CO_2 capture was $68.8/ MW-hr.

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I-2 NATURAL GAS COMBINED CYCLE (NGCC)

Aspen Plus® simulations were developed for two natural gas power combined cycle power plants using a gas turbine model that is based on the Siemens-Westinghouse W501G gas turbine and a three pressure level steam cycle. The two cases differ depending on whether CO_2 capture is included. The first case (no CO_2 capture) produces 379.1 MWe at a process efficiency of 57.9% (LHV) and is considered as a commercially available plant. The second case includes CO_2 capture based on recovering CO_2 from the flue gas stream that exits the heat recovery steam generator (HRSG). The CO_2 capture envisioned is based on a commercial amine process (Dow Chemical) [5] operating at a design of 90% CO_2 capture coupled with compression to sequester the CO_2 as a high pressure liquid. The power is reduced both due to compression and the steam required for regenerating the amine solvent. Dow Chemical has advised us that the system is both more difficult when compared with recovery from a PC power plant and more expensive due to the higher oxygen content in the exhaust. At the present time, they were unaware of any existing plant using this approach due to the high efficiency penalty expected.
The Aspen Plus® results indicated a reduction in power to 326.9 MWe and a reduction in efficiency to 49.9% (LHV). Results are summarized in the following table.

Table 4. Natural Gas Combined Results

POWER SYSTEM	NATURAL GAS COMBINED CYCLE (NGCC)	
Power Generation Cycle	NGCC "G" Gas Turbine	NGCC "G" Gas Turbine (CO2 Capture)
Net Power MWe	379.1	326.9
Net Plant Efficiency	57.9	49.9
% LHV		
Total Capital Requirement	515	911
$ / KW		
Cost of Electricity	34.7	48.3
$ / MW-hr		
NOx emissions	0.176	0.204
lb/MW-hr		
Sox emissions	---	---
lb/MW-hr		
CO2 Production		
lb/MW-hr		
a) Emitted to atmosphere	757	88
b) Sequesterable		790
Footprint (battery limits)	282	362
sq ft/MW		

I-2.1 NGCC – No CO_2 Capture

This power cycle is considered to be commercially available. The gas turbine conditions [6] (see "Gas Turbine World" - Siemens-Westinghouse W501G) used were:

Pressure Ratio: 19.2 : 1
Inlet Air Flowrate : 1241 lbs/sec
Exhaust Temperature: 1101 ^oF
Turbine Inlet Temperature: 2583 ^oF

The Steam Cycle was based on a heat recovery steam generation (HRSG) section that generates steam at three pressure levels with power recovered in a steam turbine system using a single reheat and at conditions: 1800 psia / 1000 ^oF / 492 psia / 1000 ^oF.

Emissions were based on simulation results for CO_2 and an assumed NOx level of 9 ppmv. (the table results would be slightly higher if adjusted for 15% oxygen level in the exhaust – which is often given in reports).

The capital cost estimate was based on information published in NETL reports , DOE/HQ contractor studies and from the Gas Turbine World (2001) annual summary [6]. The cost of electricity analysis was based on the EPRI Tag method.

The Footprint (battery limits) was a crude estimate based on available information in published studies (such as the footprint of the W501G gas turbine). The actual plant site would be approximately 100 acres.

In Figure 4, the process is shown with key process streams to illustrate this power plant cycle. Appendix A contains detailed information for the process streams shown.

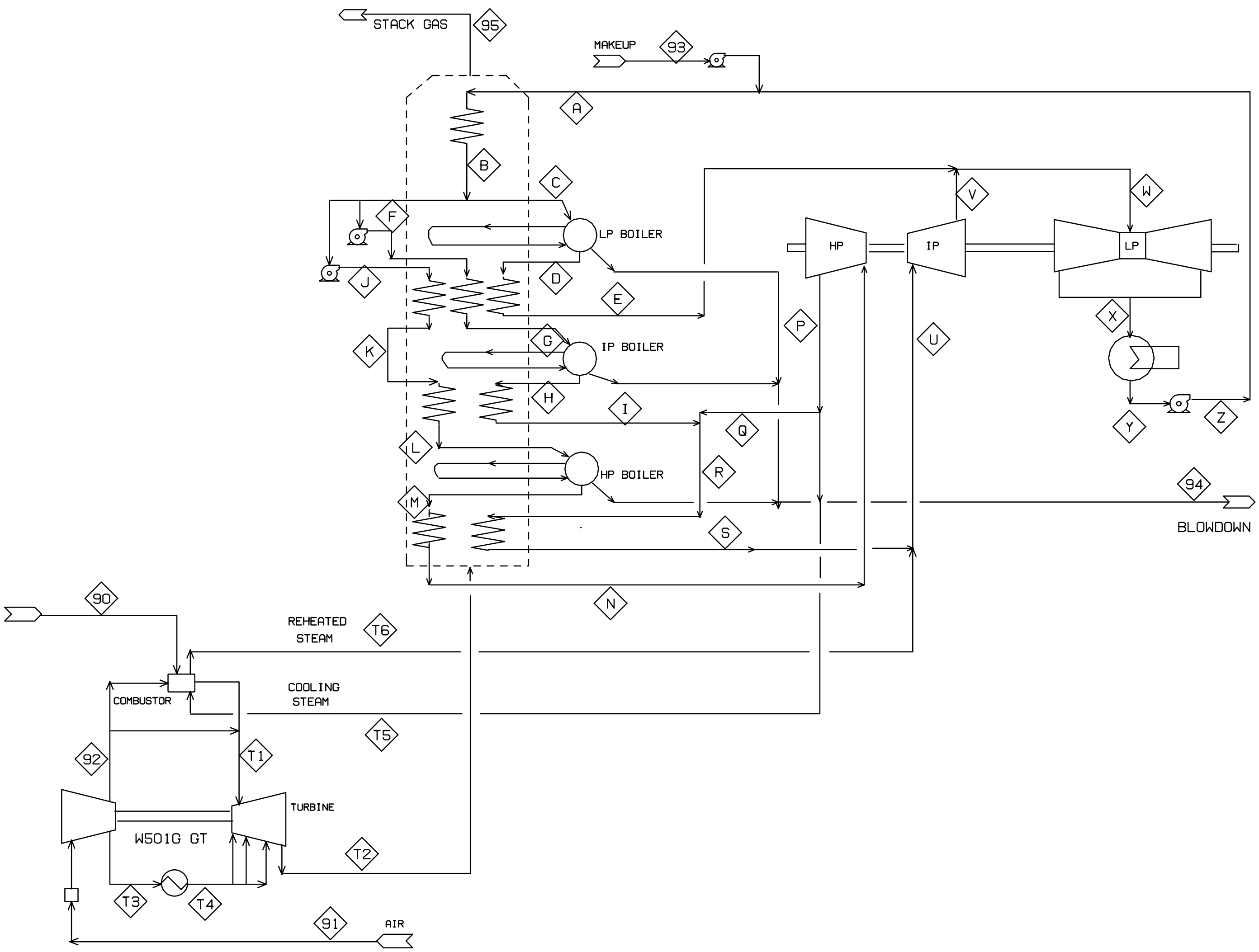


Figure 4. NGCC Power Plant

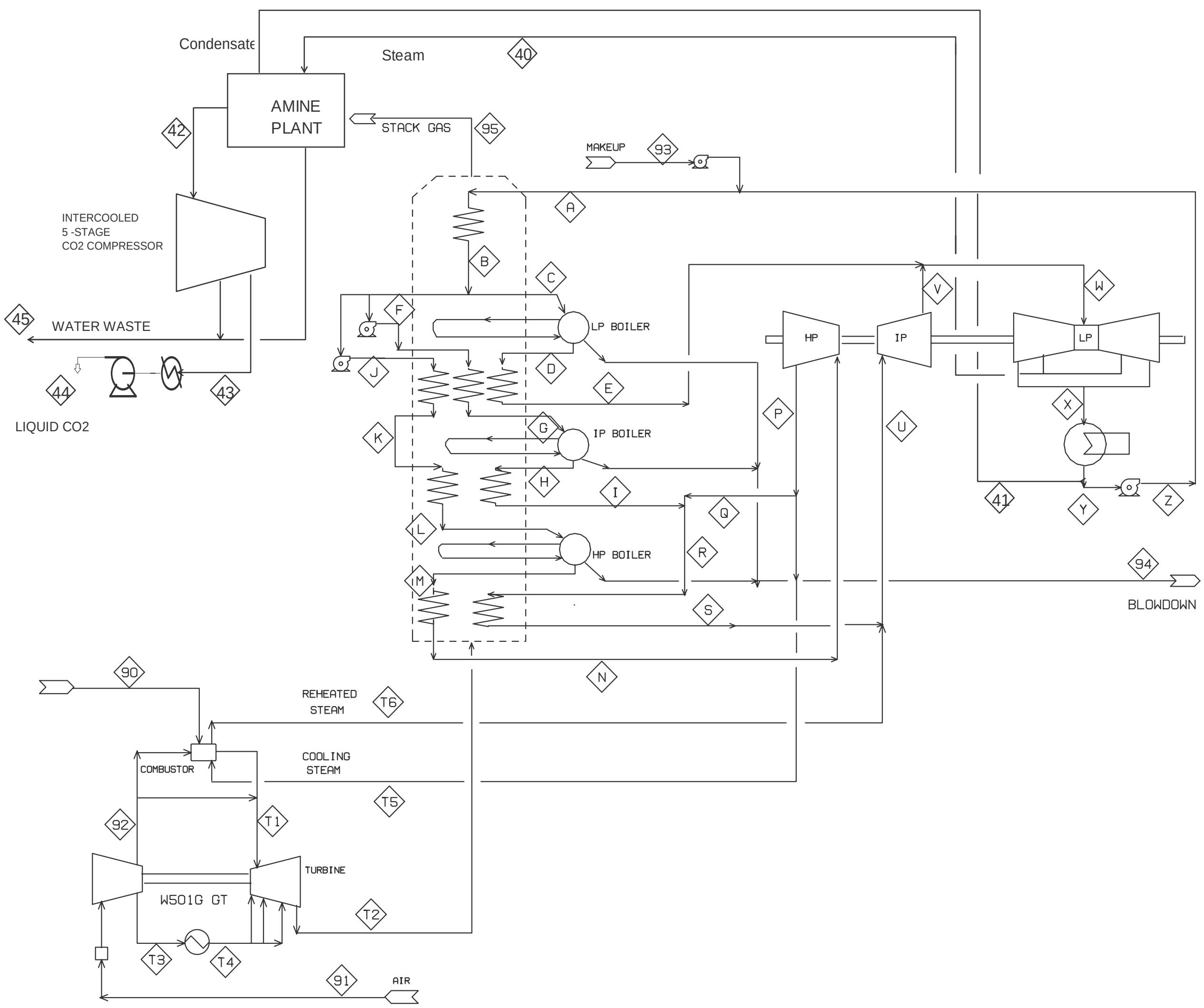
I-2.2 NGCC – CO_2 Capture

An Aspen Plus® simulation was developed based on adding a CO_2 capture process. This was accomplished by adding an amine plant followed by a compression section to the previous case. Figure 5 and Figure 6 show the modifications.

The flue gas exiting the HRSG enters an amine plant shown in Figure 6 to produce a CO_2 rich-stream. This stream is compressed in an inter-cooled five stage compressor to a pressure of 2160 psia. The high pressure CO_2 gas stream is cooled to approximately 100 ^oF to produce a liquid stream which is pumped to 3000 psia to complete the CO_2 capture. The system simulated used a design basis of 90% CO_2 capture and an energy input for the reboiler in the amine plant of 3.7 MMBtu / ton CO_2 recovered. This energy requirement is met by low pressure steam (35 psia) which is withdrawn from the steam cycle prior to the low pressure steam turbine. (see Figure 5). This results in a loss of power in the steam cycle and when combined with the compression power requirement results in a significant power penalty for CO_2 capture. Table 4 above shows that the net power produced decreases to 326.9 MWe from 379 MWe and the overall efficiency decreases to 49.9% from 57.9% (LHV).

Even when an increase of perhaps 4 – 6 percentage points in efficiency is added for an improved ATS turbine system and an improved solvent process, the Vision 21 program's efficiency goals for natural gas power cycles are not obtainable.

In Figures 5 and 6, process flow diagrams are presented with detailed process stream information provided in Appendix A. The capital cost estimate was developed by adding projections for the amine plant and the compression section. The COE results are provided in Appendix B.



NGCC (WITH CO2 CAPTURE) - W501G GAS TURBINE - 3 PRESSURE LEVEL STEAM CYCLE

Figure 5. NGCC – with CO_2 Capture

AMINE PLANT

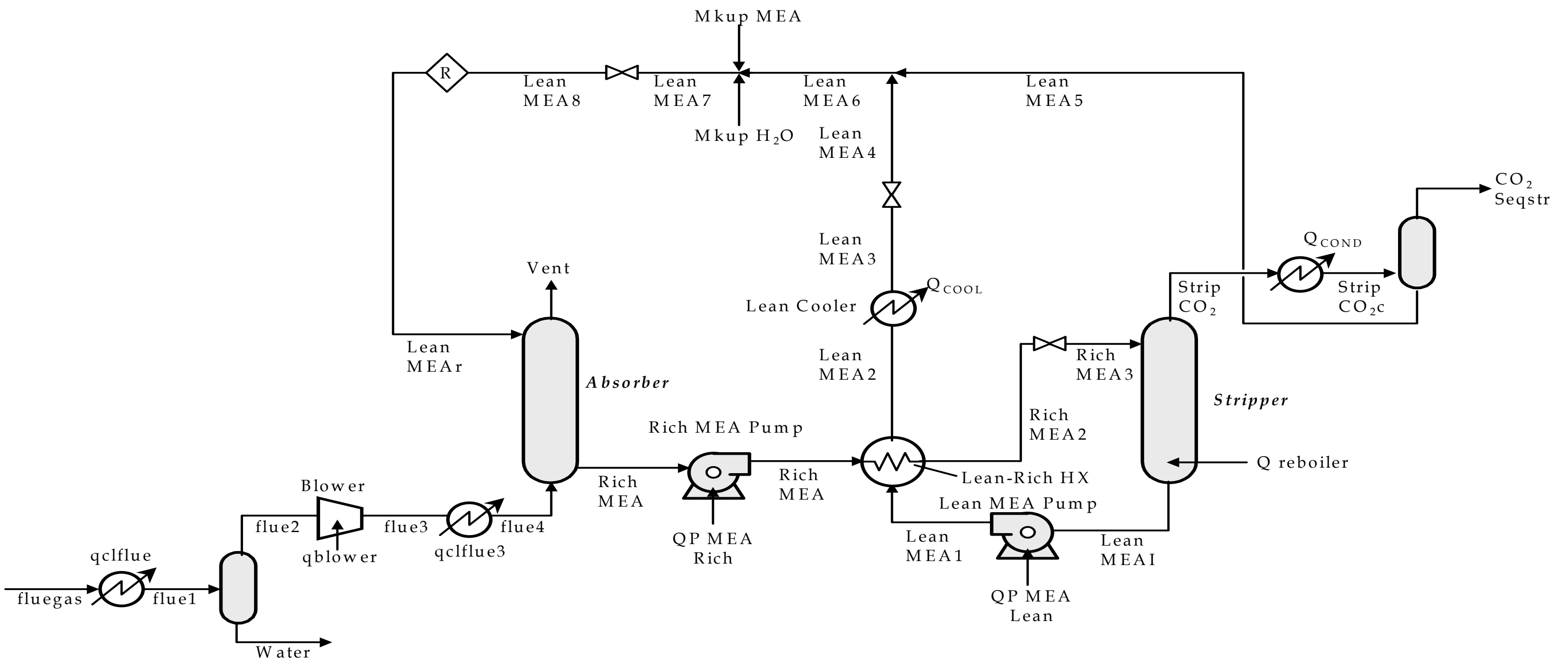


Figure 6. Amine Plant

I-3. INTEGRATED GASIFCATION COMBINED CYCLE (IGCC)

NETL/DOE has been sponsoring the research and development of IGCC as the cleanest coal-based power system available today for several decades and in a recent report (July 2002) [7] a snapshot is provided from industry's viewpoint on the outlook and needs for future research and development of both IGCC and Gasification Technologies. As part of providing a comparison with the proposed advanced coal power systems presented later in this report, a group of IGCC systems studies has been assembled based on previous NETL studies completed in FY2000. In Table 5, results are summarized for several reference IGCC cases that are viewed as near-term commercially available and for a case proposed on the inclusion of a hydrogen powered fuel cell. (These systems studies are available with additional systems based on different gasifiers on the NETL website [8].) Key assumptions include:

- Oxygen- blown Gasification (Destec [E-Gas™] or Shell) using Illinois No. 6 bituminous coal.
- Gas Cleanup for particulate matter, chloride and sulfur based on either Cold Gas Cleanup or Hot Gas Cleanup.
- Gas Turbine based on Siemens Westinghouse W501G heavy duty gas turbine with dry low-NOx combustor. (9 ppmv NOx, nominal 272 MWe – modified for syngas).
- Steam Cycle is a three pressure level process.
- Air Separation based on cryogenic process integrated with the gas turbine.
- Single-Train IGCC Power Plants.
- For the two cases that include CO_2 sequestration, the CO_2 is captured and compressed to provide a liquid product stream.
- For the case that produces high purity hydrogen, conversion to power via a fuel cell occurs at 65% of the heating value of the hydrogen produced.
- Cost of Electricity (COE) based on estimates updated to First Quarter 2002 ,

These cases demonstrate overall efficiencies (LHV basis) ranging from 40- 49%. The lower efficiencies cases include a CO_2 Sequestration penalty of 6 – 7 percentage points.

Table 5. Reference IGCC Case Results

POWER SYSTEM	INTEGRATED GASIFICATION COMBINED CYCLE (IGCC)				
	Case 1	Case 2	Case 3	Case 4	Case 5
Generation Cycle	IGCC Destec (E-Gas) CGCU "G" Gas Turbine	IGCC Destec (E-Gas) HGCU "G" Gas Turbine	IGCC Destec (E-Gas) CGCU "G" Gas Turbine (CO2 Capture)	IGCC SHELL CGCU "G" Gas Turbine	IGCC SHELL CGCU Gas Turb (ANL) (CO2 Capture)
Net Pow er MWe	400.6	400.4	358.6	412.8	351.1
Net Plant Efficiency	46.7	49.4	40.1	47.4	40.1
% LHV					
Total Capital Requirement	1374	1354	1897	1370	2270
$ / KW					
Cost of Electricity	40.9	39.1	54.4	40.6	62.9
Constant $ / MW-hr					
NOx emissions	0.165	0.165	0.185	0.160	0.182
lb/MW-hr					
Sox emissions	0.342	0.04	0.113	0.276	0.112
lb/MW-hr					
CO2 Production					
lb/MW-hr					
a) Emitted to atmosphere	1517	1431	231	1496	190
b) Sequesterable			1536		1569
Footprint (battery limits)	1092	1057	1198	1065	1168**

(** Footprint does not include fuel cell)

I-3.1 IGCC Destec (E-Gas™) Cases – No CO_2 Capture

Two reference cases were developed in FY2000 for the NETL/Gasification Technologies team and are documented on the website. They can accessed via the following URL.

http://www.netl.doe.gov/coalpower/gasification/system/destx3x_.pdf

As part of the DOE Clean Coal Technology demonstration projects, the Destec IGCC process was commercially demonstrated as the Wabash River Coal Gasification Repowering Project [9]. The DOE is currently sponsoring additional optimization studies [10] (Nexant, Global Energy) based on the results of this demonstration. This analysis and scope can accessed via the following URL.

http://www.netl.doe.gov/coalpower/gasification/projects/systems/docs/40342R01.PDF

For the present report the simulation codes developed earlier were updated to use version 10.2 of Aspen Plus® and the COE estimate was updated to first quarter 2002.

The cases have the following common process sections:

- Coal Slurry Prep - based on Illinois #6 coal, 66.6% solids.
- Destec Gasification - two stage, entrained flow, oxygen-blown, slagging gasifier.
- Air Separation Unit (ASU) - high pressure process integrated with the gas turbine.
- "G" gas turbine -W501G modified for coal derived fuel gas.
- Three pressure level subcritical reheat Steam Cycle
  - (1800 psia / 1050 ^oF / 342 psia / 1050 ^oF / 35 psia).

The approach used for gas cleanup accounts for the major differences between the two cases. For sulfur removal, Case 1 uses cold gas cleanup (CGCU) and Case 2 uses transport desulfurization hot gas cleanup (HGCU). The syngas gas cooler section following the gasifier (and integrated with the gasifier and other heat exchangers) is used for generating high-pressure superheated steam. This section is followed by a cyclone that captures particulates for recycle to the gasifier. The cooled raw fuel gas leaves the filter at a temperature of 650 ^oF for Case 1 and 1004 ^oF for Case 2. In Case 1, the raw fuel gas is further cooled (304 ^oF) and scrubbed and then sent to a gas cooling / heat recovery section before entering the CGCU section. In Case 2, the raw fuel gas enters a chloride guard bed prior to the HGCU section. Sulfur is recovered as elemental sulfur using the Claus process for Case 1 and as sulfuric acid using an acid plant for Case 2.

Process flow diagrams for these cases are shown in Figures 7 and 8. Additional flow diagrams (steam cycles) and material and energy balances summaries are provided in Appendix A and COE summaries are given in Appendix B. In Table 6 (above) the overall results obtained for power generation, process efficiency, and COE are compared for both cases.

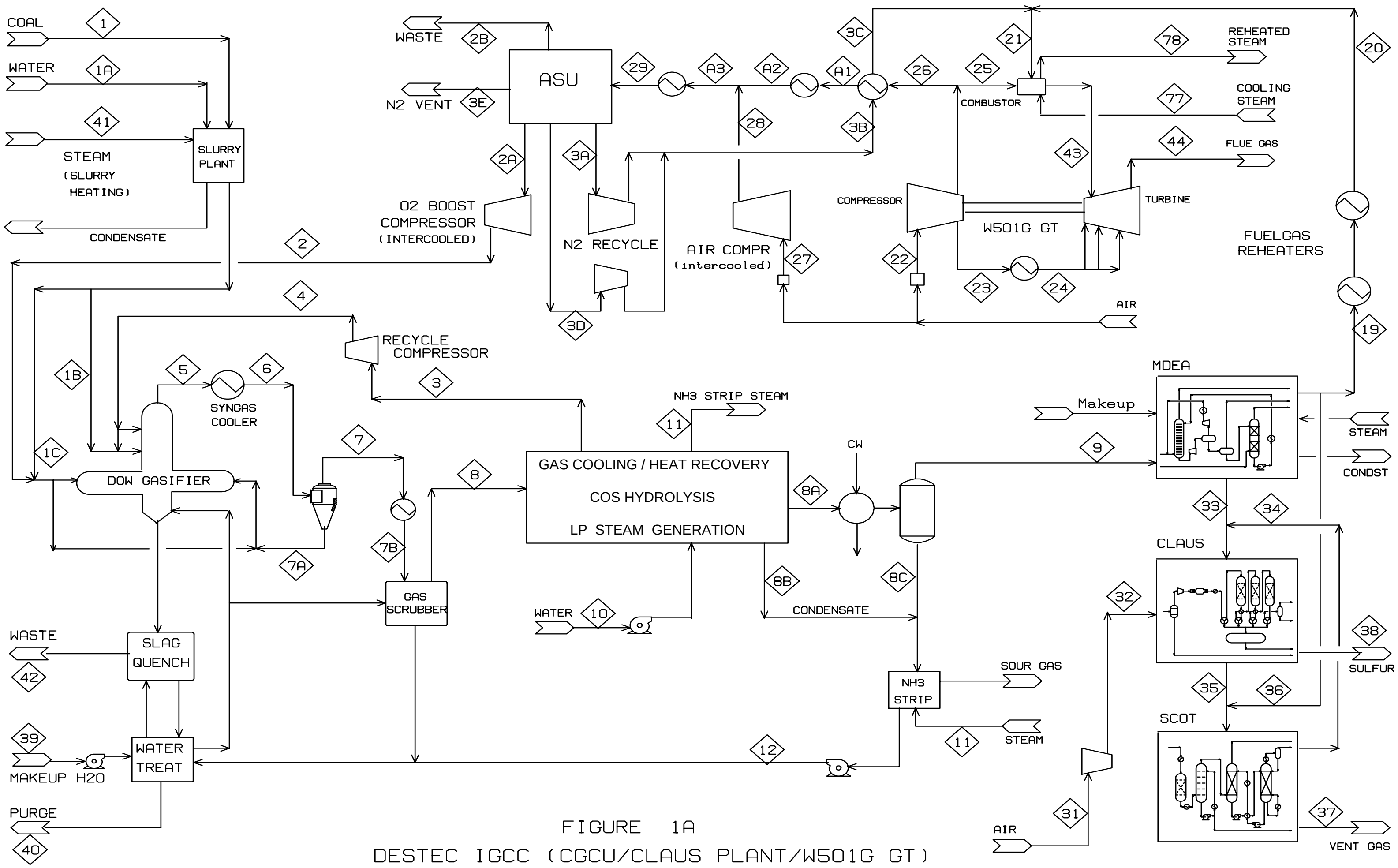


Figure 7. Case 1. IGCC DESTEC / CGCU – No CO_2 Capture

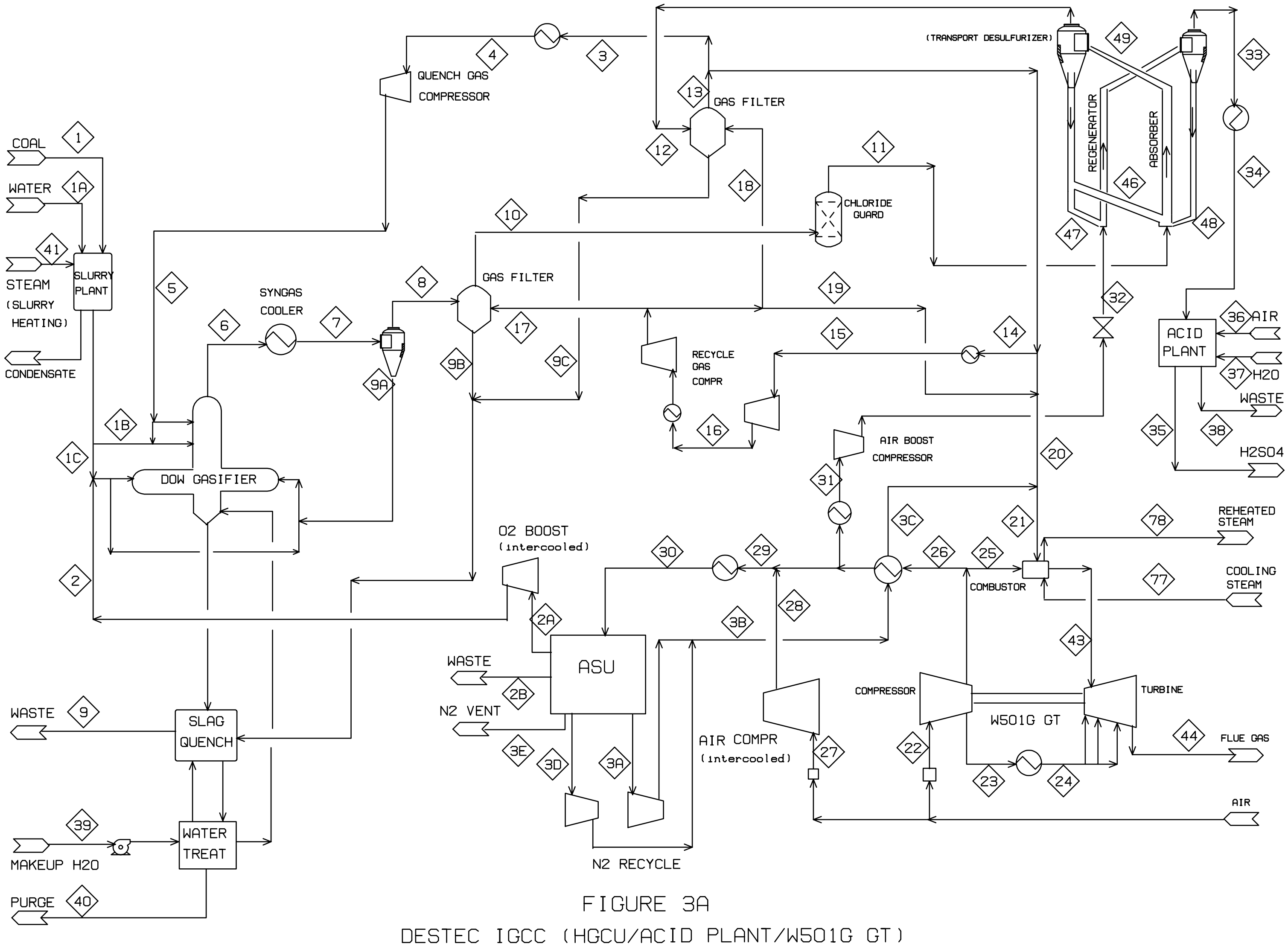


Figure 8. Case 2. IGCC DESTEC / HGCU – No CO_2 Capture

I-3.2 IGCC Destec (E-Gas™) Cases – CO_2 Capture

This case was developed based on modifying Case 1 to include CO_2 capture and involves the following changes in the power plant design:

- Shift Reaction Section using a catalytic process to accomplish the following reactions:

$$CO + H_2O \leftrightarrow CO_2 + H_2 \quad \text{(water-gas shift)}$$
$$COS + H_2O \leftrightarrow CO_2 + H_2S \quad \text{(COS Hydrolysis)}$$

- Selexol process for both H_2S and CO_2 removal. This replaces the MDEA section in Case 1.

- CO_2 compression in a multistage (5-stages) intercooled compressor to 2100 psia, cooling to 100 ^oF (liquid) and pumped to 3000 psia for storage.

- Gas Turbine – the gas turbine is fueled with the hydrogen rich fuel.

<u>Shift Reaction Section</u>

The catalyst chosen (named SSK , "Sulfur Tolerant Shift Catalyst") and process conditions were designed based on information provided to NETL (Patrick Le - 1997) by Haldor Topsoe, Inc. [11]. The catalyst can be used for both the water-gas shift and the COS hydrolysis reactions and was initially developed at EXXON Research & Engineering Laboratories and extended for industrial use by Haldor-Topsoe. The main features of the SSK catalyst are:

- unique property of being highly active for the reaction of carbon monoxide with steam in the presence of hydrogen sulfide.
- maintains its activity over a wide range of operating conditions including temperatures to 890 ^oF.
- No specific catalyst poisons are known for SSK. Insensitive to even relatively large amounts of chlorine.

The simulation model represents this section using a two-bed shift unit with intercoolers / aftercoolers for heat recovery that was integrated into the steam cycle. The required shift steam was bled from the steam cycle at conditions of 632 ^oF and 390 psia and mixed with the raw syngas and sent to the first catalytic bed. The first bed converts 70% of the CO and nearly all the COS. The exiting stream is cooled to 460 ^oF before entering the final stage. The overall conversion obtained for CO was 95%. After cooling, the stream is sent to the Selexol process section.

<u>Selexol Process Section</u>

This section is used to selectively remove H_2S in a product stream that is sent to a Claus unit for sulfur recovery and to recover CO_2 in a product stream that is sent to a compression unit for sequestration. The Selexol process is an absorber-stripper system that uses a designer physical solvent (Dow Chemical, formerly Union Carbide) containing a mixture of glycols. In the

Aspen Plus® simulation, the overall recoveries were represented and the detailed chemistry not modeled. The shifted cooled syngas is considered to enter an absorber that preferentially removes the H_2S by using a lean Selexol solvent that is loaded with CO_2. The rich solvent leaves the absorber and is sent to a stripper for regeneration. Low pressure steam used for the stripper reboiler is supplied from the steam cycle. The sweet syngas stream exits the first absorber and is sent to a second absorber that uses an unloaded solvent to remove CO_2 and additional H_2S. The CO_2 rich solvent stream leaves the second absorber and is recovered by flashing CO_2 vapor off the liquid at a reduced pressure. (Alternately, a second stripper could be used.) The cleaned syngas in the current simulation aimed at power production is reheated and sent to the gas turbine combustor. Alternately, if hydrogen is the desired product, the hydrogen rich syngas stream would be sent to a pressure swing absorption process for further purification with a residual fuel stream available for use in power generation. (see Case 5 that uses Shell gasification for this approach).

(It should be noted that the use of a double absorber system will result in improved H_2S removal which may approach the goals set for hot gas cleanup units {Case 2}. The sulfur emissions levels reported in Table 5 assumed that the SCOT waste stream was not recycled to the gasifier. Recycling would perhaps reduce the values shown by one-half. {HGCU levels}.)

<u>CO_2 Compression Section</u>

The CO_2 from the Selexol section is considered to be recovered in two streams from flashes at pressures of 40 psia (90%) and 15 psia (10%). The lower pressure stream is compressed to 45 psia and combined with the larger stream and sent to a multistage (5 stages) intercooled compressor to approximately 2100 psia. The supercritical stream is cooled to approximately 100 ^oF (liquid) and pumped to 3000 psia for storage. This section requires 19.9 MWe of power.

<u>Gas Turbine Section</u>

The gas turbine is fueled with the hydrogen rich syngas stream. To maintain approximately the same turbine power output and turbine inlet temperature as in Case 1 and Case 2, the coal flowrate (27% increase) to the gasifier and the nitrogen recycle from the ASU were adjusted.

This case results in an overall decrease in process efficiency (LHV) of 6.6 percentage points when compared with Case 1 (no CO_2 capture) which is attributable to the additional compression power requirements and the reduction in steam cycle output due to the steam requirements of the shift reaction section. The COE also shows a corresponding increase to 54.4 from 40.9 $/MW-hr.

Flow diagrams and M&E balance summaries are provided in Appendix A and the COE estimate is provided in Appendix B.

I-3.3 IGCC Shell Cases

Two reference cases are included based on the Shell Gasification process. Case 4 was developed in FY2000 (EG&G) [12] and Case 5 in FY2001 (ANL, J. Molburg, R. Doctor, N. Brockmeier) [13] for the NETL/Gasification Technologies team. The documentation can be accessed via the following URLs.

Case 4:
http://www.netl.doe.gov/coalpower/gasification/system/shell3x_.pdf

Case 5:
http://www.netl.doe.gov/coalpower/gasification/pubs/pdf/igcc-co2.pdf

Case 4 corresponds to an IGCC system that is analogous to Case 1 differing primarily in the use of a Shell gasifier replacing the Destec gasifier. Case 5 was developed using Case 4 as a starting point and making modifications to enable CO_2 capture making this case similar to Case 3 that used the Destec gasifier. Additionally, Case 5 has the objective of producing a hydrogen product stream of high purity as either a chemical product or as fuel for an advanced power module such as a fuel cell.

Case 4 (Shell IGCC) consists of the following major sections:

- Coal Prep - coal grinding and fluid-bed dryer to approximately 5% moisture.
- Shell Gasification - entrained flow, oxygen-blown, slagging gasifier.
- Air Separation Unit (ASU) - high pressure process integrated with the gas turbine.
- Cold Gas Cleanup – MDEA, Claus, SCOT – sulfur removal and recovery.
- "G" gas turbine -W501G modified for coal derived fuel gas.
- Three pressure level subcritical reheat Steam Cycle
  - (1800 psia/1050 ^oF/342 psia/1050 ^oF / 35 psia).

The raw fuel gas cooler section following the gasifier (and integrated with the gasifier and other heat exchangers) is used for generating high pressure superheated steam. This section is followed by a ceramic filter that captures particulates for recycle to the gasifier. The cooled raw fuel gas leaves the filter at a temperature of 640 ^oF. The raw fuel gas is further cooled, enters a COS hydrolyzer, and is scrubbed (removes remaining particulates, ammonia and chlorides) before entering the CGCU section. Sulfur is recovered as elemental sulfur using the Claus process for Case 1. The cleaned fuel gas is reheated and sent to the gas turbine for power generation. The turbine exhaust enters a HRSG that generates steam at three pressure levels for use in the steam cycle. The overall process efficiency is 47.4 % (LHV).

A process flow diagram for this case is shown in Figures 9. Additional flow diagrams (steam cycles) and material and energy balances summaries are provided in Appendix A and a COE summary is in Appendix B. In Table 6 (above) the overall results obtained for power generation, process efficiency, and COE are listed.

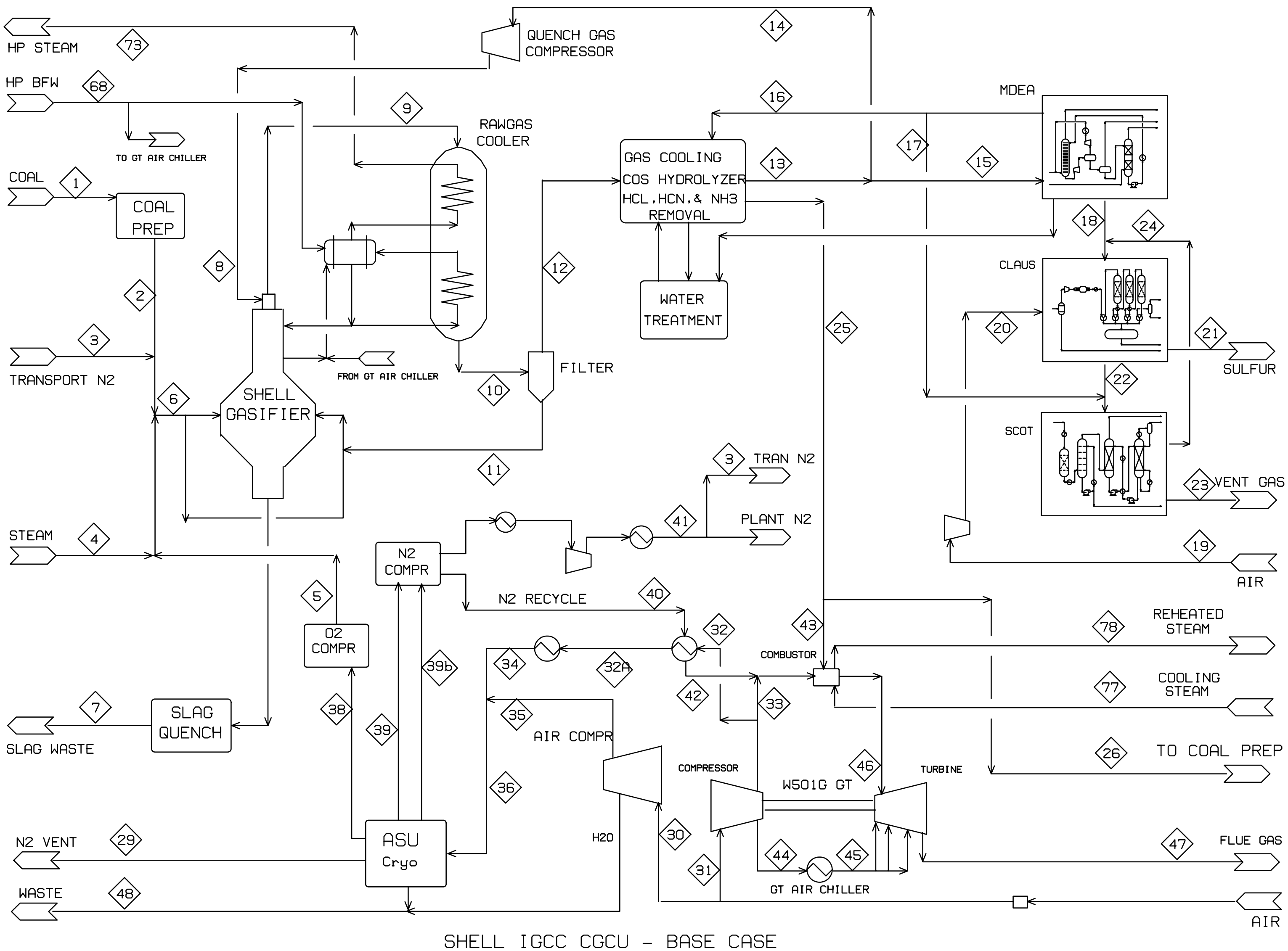


Figure 9. Case 4. IGCC SHELL / CGCU – No CO_2 Capture

For Case 5, ANL made the following modifications to Case 4:

- Shift Reaction Section - The shift reaction is used to convert CO in the gasifier product stream to CO_2 and hydrogen using two beds of sulfur-tolerant shift catalyst. The first bed was used to convert 76% of the CO and 98% of the remaining CO in the second bed. Steam requirements are higher than for Case 3 (Destec) since the gasifier in this case uses a dry coal feed as opposed to the slurry coal feed. Again part of the steam energy requirement is met by recovering heat between the catalyst bed sections and after the second bed.

- Glycol Recovery Sections for both H_2 and CO_2 - This is similar to the approach used in Case 3 and replaces the MDEA section used for the H_2S recovery in Case 4.

- Pressure Swing Absorption Section – Since the objective was to produce a highly purified H_2 stream, this process is required. In Case 3, this approach wasn't used since the hydrogen was used in a gas turbine. The residual stream from the PSA process has sufficient heating value remaining to be used as fuel in a midsize gas turbine.

- Replacing "G" gas turbine / HRSG / Steam Cycle – The residual fuel from the PSA was reheated and used in a gas turbine that produces 62 MWe . The HRSG/Steam Cycle from Case 4 were discarded and replaced to reflect the modified process design. The steam cycle produces 91.5 MWe.

In Figure 10, (Figure 1 from the above website reference), a block diagram showing the major process sections is shown. For comparisons with other IGCC reference cases, the hydrogen produced was assumed in the present report to be converted to power based on assuming an advanced process (e.g., fuel cell) having a cost of \$400/MWe. Based on ANL projections, (see Table 2 of the ANL report), conversion at an efficiency of 65% would add 275 MWe to the process for a net power production of 351.1 MWe . The calculated overall process efficiency is 40.1% and the COE is 62.9 \$/MW-hr. This indicates substantial penalties in efficiency and cost to sequester the CO_2.

Figure 10. Case 5. SHELL / CO_2 Capture / Advanced Power Module

I-4. Summary – Reference Plants

The reference plants included in the previous sections were provided to have points for comparison for the advanced fossil power systems considered in the remainder of this report. The systems were projected for a nominal plant size of 400 MWe (for cases having no carbon dioxide capture) and with a consistent cost of electricity analysis based on the EPRI TAG method (see Appendix B). Additionally, cases were included to illustrate the significant penalty that occurs with the addition of carbon dioxide sequestration that may be required for Vision 21 power plants.

The PC power plant (no CO_2 capture) represents a primary system presently employed for coal based power plants in this country. It is expected that these plants will be subjected to further requirements for improved emissions than the results shown in Table 2. The efficiency determined of 39% (LHV) can be improved to about 43-47 % based on using a super-critical steam cycle, higher steam temperatures and double reheat cycles. All these involve additional costs. The two remaining PC cases included CO_2 capture either using flue gas cleanup or a proposed system based on using oxygen. Both cases illustrate an energy penalty of 8 – 10 percentage points and approximately double the COE results from the base system.

Two NGCC systems were included based on using a gas turbine model of the Siemens-Westinghouse W501 G gas turbine. The inclusion of CO_2 capture reduces the process efficiency from 58% (LHV) to 50% and increases the COE from 33.1 ($/MW-hr, constant $) to 46.4. Projections provided by both Siemens-Westinghouse and General Electric to the DOE anticipated commercial NGCC systems (no CO_2 capture) with efficiency above 60% (LHV). NETL/DOE is currently sponsoring research [4] aimed at improving the flue gas CO_2 capture to reduce the energy penalty.

The IGCC cases included were for systems aimed at providing electrical power and not a mix of both power and chemicals. The penalty (for the cases considered) associated with CO_2 capture is 6.5 – 7.3 percentage points. Since the CO_2 capture involves treating the generated fuel gas rather than the flue gas of a NGCC process, the capture is easier and more feasible both form a technical and economic viewpoint. However, this is balanced by the inherent difference in the carbon/hydrogen content of coal versus natural gas. The arguments made for IGCC systems are usually made based on the potential offered for feedstock diversity (and product diversity) and the energy security based on using our (USA) most abundant resource, coal. The economic comparison with the NGCC is dependent on the price assumed for natural gas. (A value of $3.2/MM BTU was used for natural gas cases.). Using the near-term commercial systems for IGCC, the expected efficiency is significantly lower than the 60% (HHV) goal of Vision 21 plants based on coal.

II. ADVANCED POWER CYCLES

II-1 Hydraulic Air Compression Cycle (HAC)

The use of hydraulic air compression (HAC) has been proposed as a means for increasing the efficiency of high-efficiency power cycles to meet the Vision 21 objectives for both natural gas and coal [14]. In this approach, low pressure air is entrained in a large volume of water with the resulting mixture pressurized using a deep well or reservoir. The high pressure air produced can be used to replace the high pressure air normally supplied by the gas turbine compressor in a combined cycle power system. Conceptually, the gas turbine in either the NGCC or IGCC is modified by removing the compressor while retaining the combustor and expander sections. Additionally, the proposed HAC power cycles employ the expander exhaust in a recuperator to preheat the high pressure air sent to the combustor. This either eliminates the need for a steam cycle or greatly reduces its size and cost. A simplified diagram illustrating the HAC is shown in Figure 11.

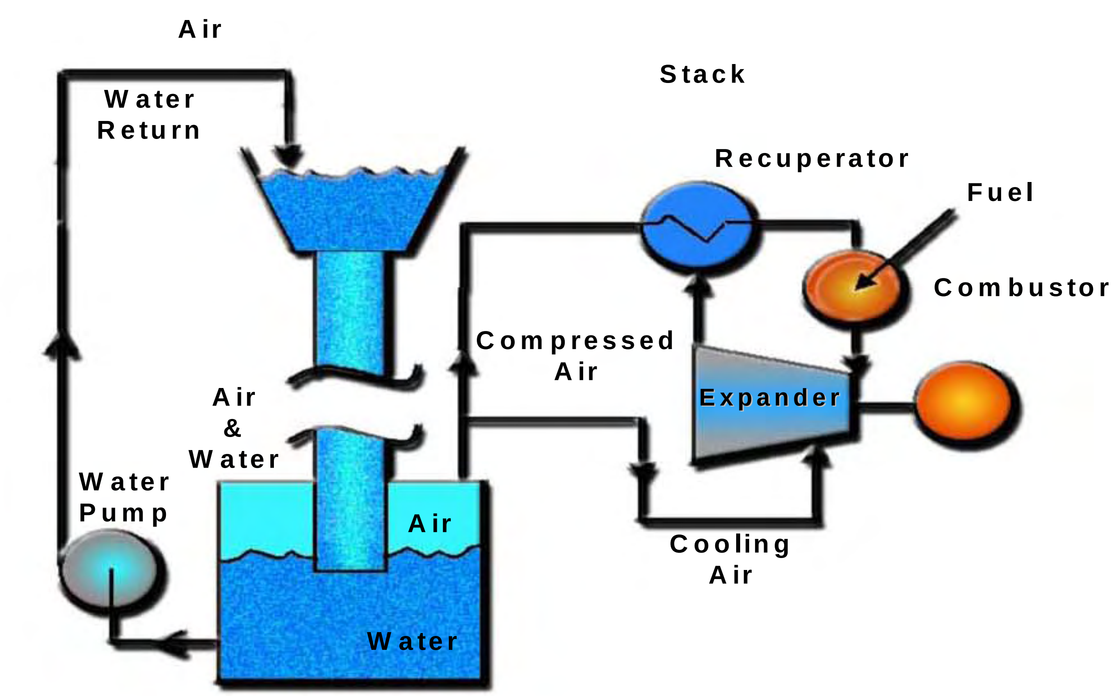


Figure 11. Hydraulic Air Compression Power Block – closed loop water cycle.

The following simulation cases were developed to provide high pressure air to the combustor using the Hydraulic Air Compression:

- Case 1 - Natural Gas Cycle without CO_2 capture. This case modifies the NGCC reference plant case.
- Case 2 - Natural Gas Cycle with CO_2 capture. This case extends Case 1 by adding an amine plant / compression sections to recovery the CO_2.
- Case 3 - Coal Cycle without CO_2 capture. This case modifies the Destec IGCC (CGCU) reference plant case.
- Case 4 - Coal Cycle with CO_2 capture. This case modifies a Destec IGCC (High Pressure Gasifier/Gas Shift Reaction/HGCU) process plant. This is a case developed for this report.

The results obtained from these simulations are provided in Table 7.

Table 6. Hydraulic Air Compression Cycles

POWER SYSTEM	HYDRAULIC AIR COMPRESSION (HAC)			
Generation Cycle	HAC NATURAL GAS	HAC NATURAL GAS (CO2 CAPTURE)	HAC Destec (E-Gas) CGCU	HAC Destec HP (E-Gas) HGCU (CO2 CAPTURE)
Case	1	2	3	4
Net Power MWe	323.5	300.2	325.9	312.4
Net Plant Efficiency	53.2	43.8	43.8	35.2
% LHV				
Total Capital Requirement	681	1140	1436	2189
$ / KW				
Cost of Electricity	44.2	61.0	47.0	65.5
$ / MW-hr				
NOx emissions	0.194	0.210	0.193	0.204
lb/MW-hr				
Sox emissions	---	---	0.337	0.048
lb/MW-hr				
CO2 Production				
lb/MW-hr				
a) Emitted to atmosphere	824	100	1561	142
b) Sequesterable		899		1870
Footprint (battery limits)	179	230	1293	1583
sq ft/MW				

II-1.1 Hydraulic Air Compression Cycle (HAC) – Natural Gas

Aspen Plus® simulations were developed to estimate the approximate performance and cost estimate for cases with and without CO_2 capture. These cases essentially modify the reference NGCC cases by replacing the air compressor with air obtained from the HAC approach. The combustor and turbine sections were assumed to be the same as the W501 G gas turbine.

The HAC process assumed that the air normally required for the W501 G air compressor was blown into an air/water induction system. The water usage into the closed loop system was set using the estimation method provided in a NETL sponsored study [14]. The resulting water/air mass ratio obtained was 1115. [15]. This large water usage leads to a requirement for a number of large pumps for recirculation. The high pressure air produced and delivered to the combustor was preheated in a recuperator using the exhaust stream from the gas turbine expander. For the case without CO_2 capture, the air is preheated to 950 ^{o}F and the cooled exhaust stream enters a small heat recovery section to generate low pressure (35 psia) steam used for combustor duct cooling. After being heated in the combustor duct, the steam is sent to a small steam turbine. For the case with CO_2 capture, the air was only preheated to 725 ^{o}F and a larger HRSG used since a large amount of steam is required for the stripper reboiler in the amine based CO_2 recovery process (see Figure 6 – amine plant).

Emissions of CO_2 were based on simulation results and NOx was estimated as 9 ppmv as projected for "G" turbine combustor performance. The cost estimates were based on modifying the NGCC reference plant cases. Reductions were subtracted from the total capital for the elimination of the air compressor, HRSG and steam turbines. Additions for the following: hydraulic air compression blowers and pumps (40 MWe), recuperators (large area heat exchangers), reservoir well (650 ft depth, 20 ft diameter), and for miscellaneous HAC equipment ($50 / KW). The footprint estimates were assumed to be equal approximately to those of the NGCC reference plants with an additional 1 acre for the HAC related equipment. Again the total plant sites were assumed to cover 100 acres.

The overall process efficiencies (LHV) obtained were 53.2 % (no CO_2 recovery) and 43.8 % (with CO_2 recovery). The total capital requirements and COE estimates made with conservative assumptions are provided in Table 7. The results for both efficiency and COE are higher than comparable reference cases given in Table 1. The lower efficiency is related to the large power requirements of the recirculation water pumps and the requirement to add a recuperator to preheat the high pressure air. The inclusion of the recuperator using the turbine exhaust essentially eliminated the power produced by the steam turbines in the reference cases. These closed loop HAC systems will be unable to obtain the goals of the Vision 21 power plants.

The two cases are shown in Figure 12 and Figure 13. Appendix A contains material and energy flow rate summaries and Appendix B includes the COE spreadsheet summaries.

CASE 1

HYDRAULIC AIR COMPRESSION CYCLE - NATURAL GAS - NO CO2 SEQUESTRATION

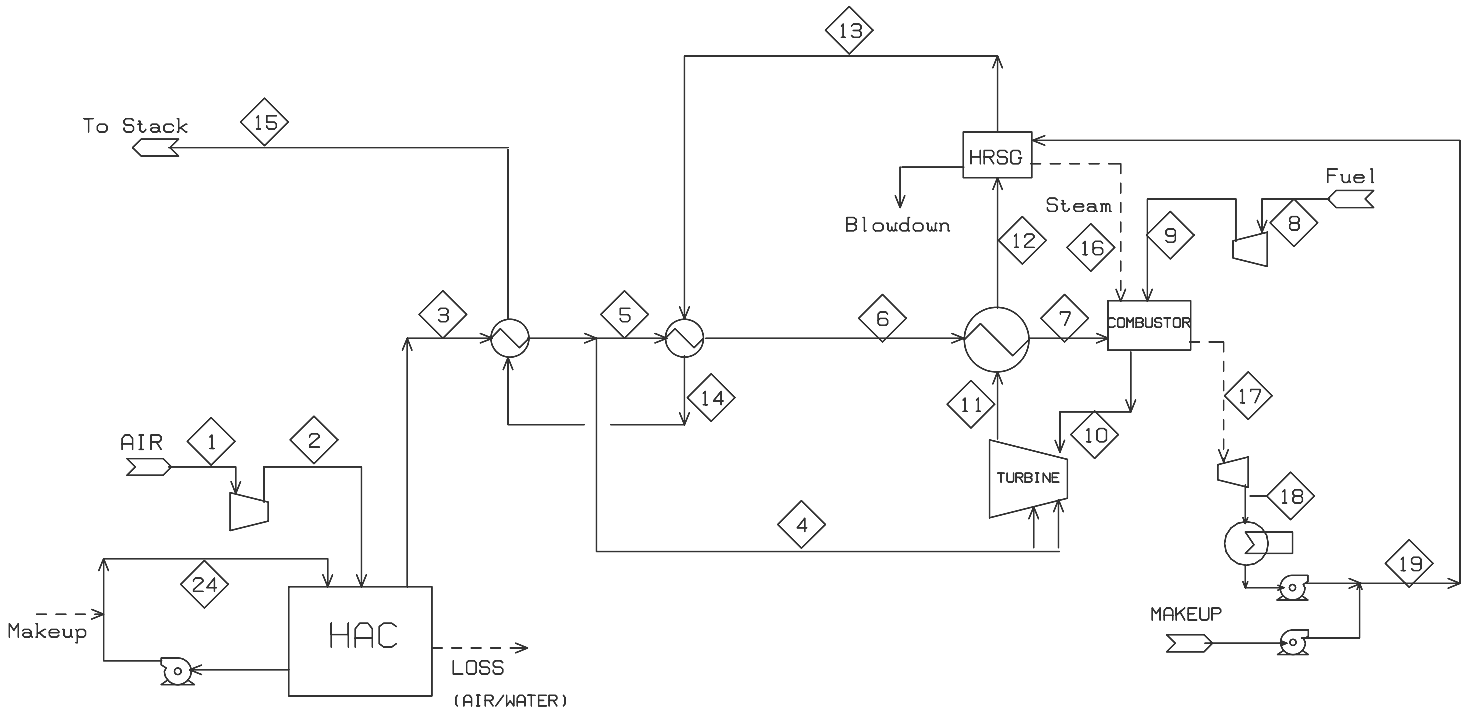


Figure 12. Case 1 - Natural Gas HAC – without CO_2 Capture

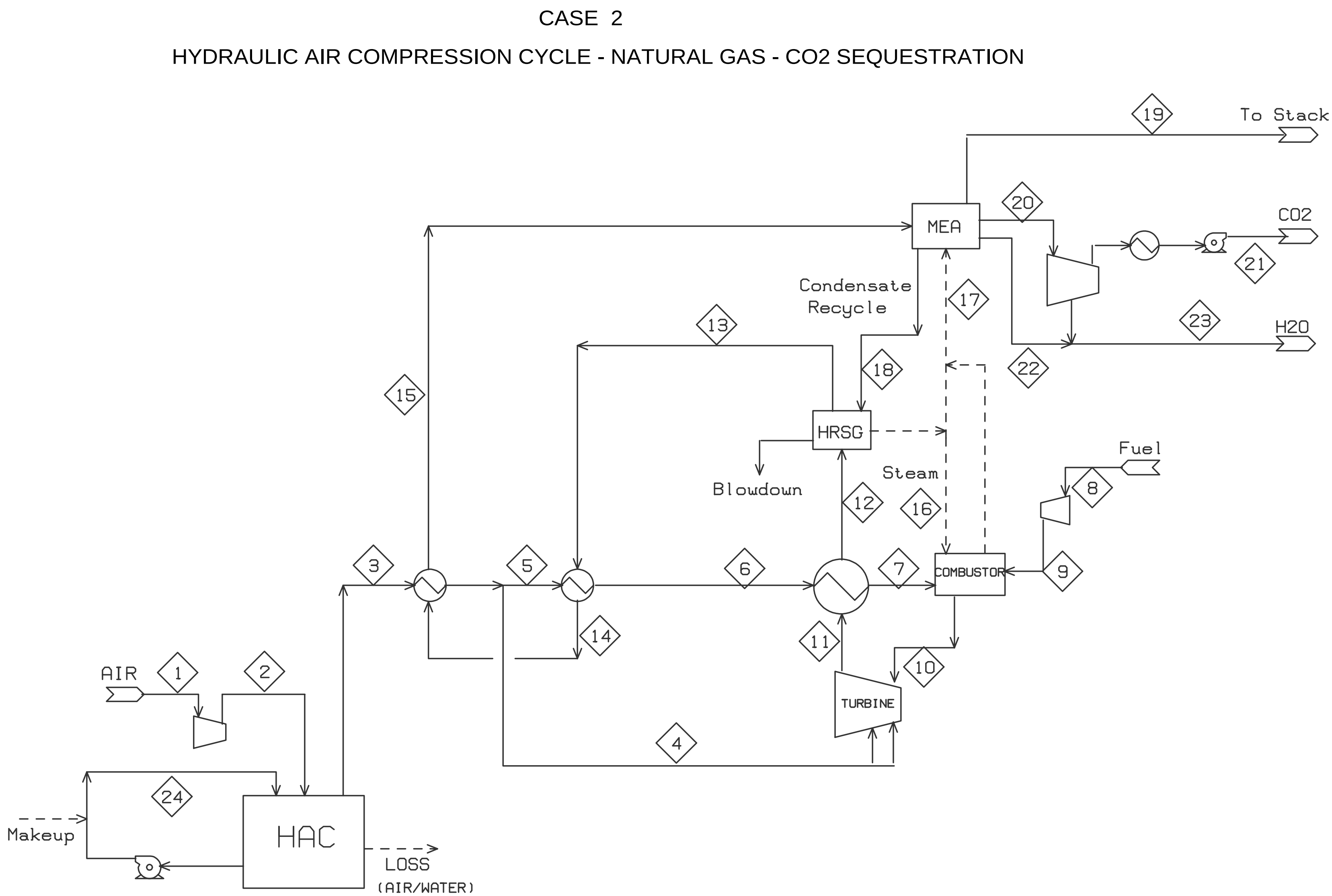


Figure 13. Case 2 – Natural Gas HAC – with CO_2 Capture

II-1.2 Hydraulic Air Compression Cycle (HAC) – Coal – without CO_2 Capture

This case is based on modifying the IGCC reference case based on the Destec gasification process that uses CGCU for sulfur recovery. The modifications include:

- The HAC is used to replace the gas turbine's air compressor. High pressure air is supplied to both the gas turbine combustor and the air separation unit (ASU). As in the natural gas cases, the air flowrate required for the combustor and ASU is fed to the HAC module. Nitrogen available from the ASU was used to replace chargeable cooling air for cooling in the turbine expander. The water flow rate is set at 1115 times the air flowrate. (mass basis).

- A recuperator is added that uses the turbine exhaust to preheat air sent to the combustor. The turbine exhaust leaves the recuperator at 265 ^oF and is sent to a stack.

- The reference case steam cycle (HRSG/steam turbines) that generates steam at three pressure levels is replaced with a smaller system (33 MWe) based on generating steam at a single high pressure. The steam generation is mainly now due to the syngas cooler since the heat available in the turbine exhaust was used in the recuperator section for preheating air.

- The cost estimate is based on adjusting the reference case for sections removed and used the same algorithms for HAC related items as in the natural gas case. The footprint was somewhat smaller due to the elimination of the larger HRSG/Steam Turbine sections found in the reference case. Additionally, since the net power increased, the footprint on a (ft^2 / MWe) basis is approximately 20% smaller.

The net power produced decreased from the reference IGCC case by 77 MWe and the COE increased to 47.0 from 40.9 ($/MW-hr). The overall process efficiency obtained was 43.8 % (LHV) or 42.3% (HHV). Again the efficiency falls significantly below the 60% (HHV) goal of Vision 21 for a power system based on coal. In Figure 14 and Figure 15, process flow diagrams are shown. In Appendix A, summaries are provided for material and energy flowrates. In Appendix B, the COE spreadsheet is provided.

Case 3

HYDRAULIC AIR COMPRESSION CYCLE - COAL SYNGAS - NO CO_2 SEQUESTRATION

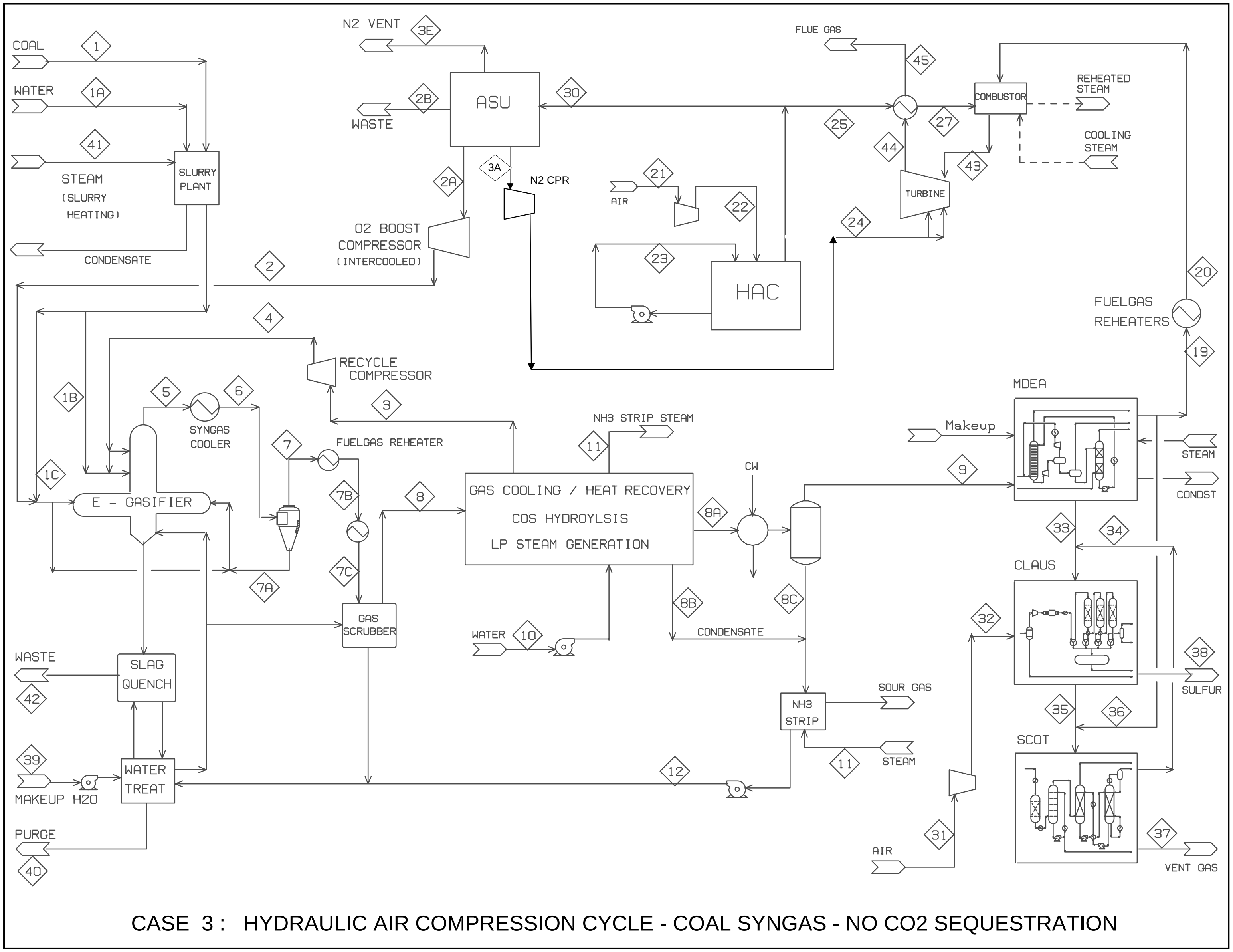


Figure 14. Case 3 - Coal Syngas HAC – without CO_2 Capture

Case 3

HYDRAULIC AIR COMPRESSION CYCLE - COAL SYNGAS - NO CO_2 SEQUESTRATION

STEAM CYCLE

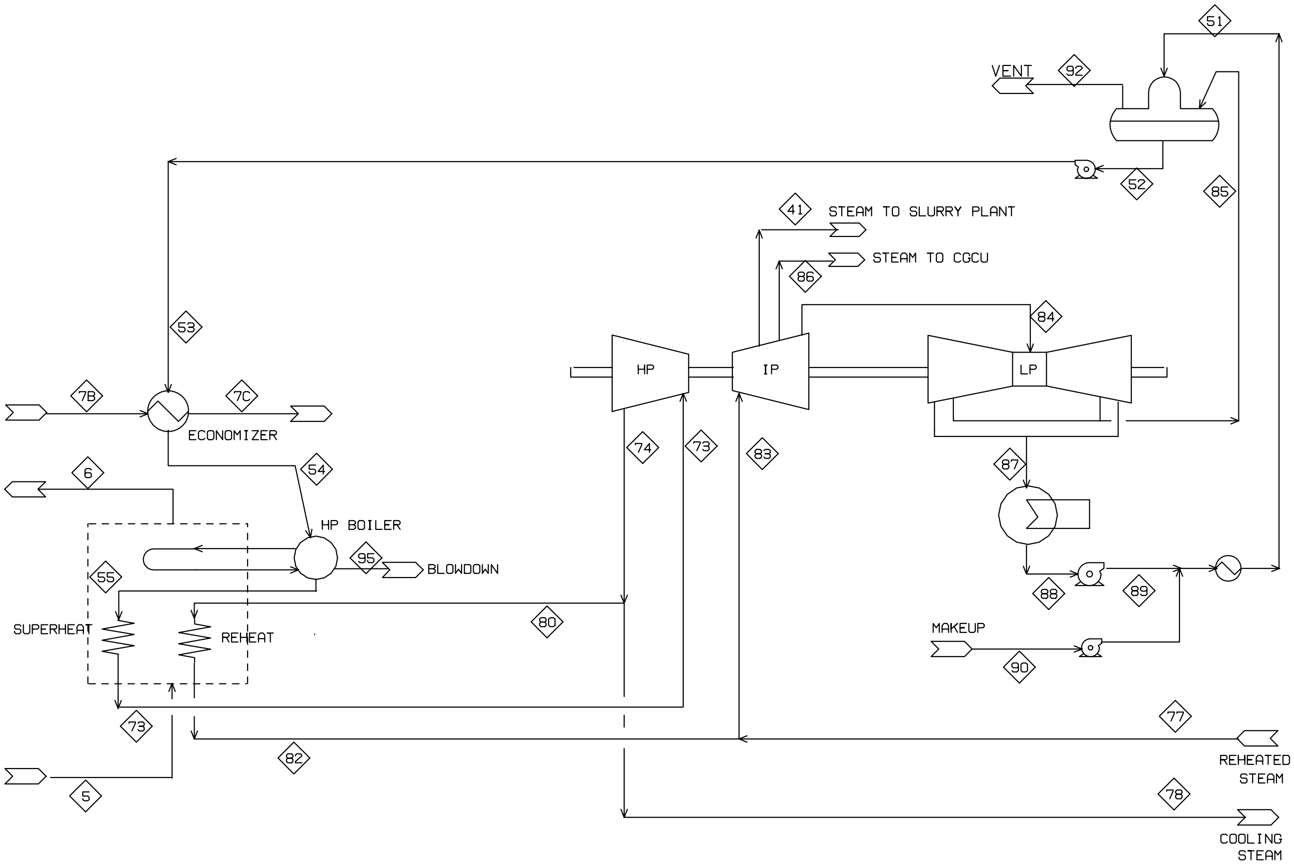


Figure 15. Case 3 - Steam Cycle

II-1. 3 Hydraulic Air Compression Cycle (HAC) – Coal – with CO_2 Capture

The reference Destec IGCC cases showed an advantaged of 2.7 percentage points in overall process efficiency when using HGCU in place of CGCU for sulfur removal and lower SOx emission levels. (see Table 6). This was the primary reason for using the Destec IGCC reference case based on HGCU as the starting point for developing the present HAC case since a significant energy penalty is expected for sequestrating the CO_2. An additional reason was that having a cleaned coal syngas at high temperature would allow the use of a Hydrogen Separation Device (HSD) currently being developed with DOE funding at ORNL [16]. The HSD is a membrane catalytic reactor being designed to both shift the coal syngas and separate out a high purity hydrogen stream. The modifications made to the reference case include the following:

- Gasifier pressure was increased to enable the downstream HSD device to have an inlet pressure of approximately 1000 psia. This also increases the power requirements for the oxygen boost compressor that supplies the gasifier. The cost analysis considers that two gasifier trains will be required based on information provided by Destec (now Global) to the DOE in previous contractor studies [17].

- A model for the HSD was added following the HGCU section. Steam at 1000 psia was added for accomplishing the shifting of the coal syngas stream. The HSD produces two streams, a high pressure CO_2 rich-stream and a low pressure high purity H_2 rich-stream.

- The CO_2-rich stream (with residual fuel gas) is sent to a power turbine and proceeds to an oxygen fired combustor to burn any residual fuel before entering a HRSG for steam generation. This stream is further cooled before entering a multi-stage compression section that raises the pressure to 2100 psia. Subsequent cooling to 100 ^{o}F produces a liquefied product stream.

- The hydrogen-rich stream is sent to a separate HRSG for steam generation before entering a compression section. The hydrogen is now available for use as a fuel in the HAC module.

- The HAC module is based on Case 3 (see above).

- The steam cycle developed recovers energy from the gasifier syngas cooler, the acid plant section, and the two HRSG sections that follow the HSD device.

The inclusion of the HAC system again results in a power plant having a significant loss in net power due. This case produced 312 MWe at an overall efficiency of 35.2 % (LHV). Compared to Case 3, the CO_2 recovery resulted in an energy penalty of 8.6 percentage points and an increase in the COE estimate to 65.5 from 47.0 ($/MW-hr). Process flow diagrams are shown in Figure 16 and Figure 17. Appendix A lists summaries for the material and energy flowrates and Appendix B lists the COE spreadsheet results.

Case 4

HYDRAULIC AIR COMPRESSION CYCLE - COAL SYNGAS - CO_2 SEQUESTRATION

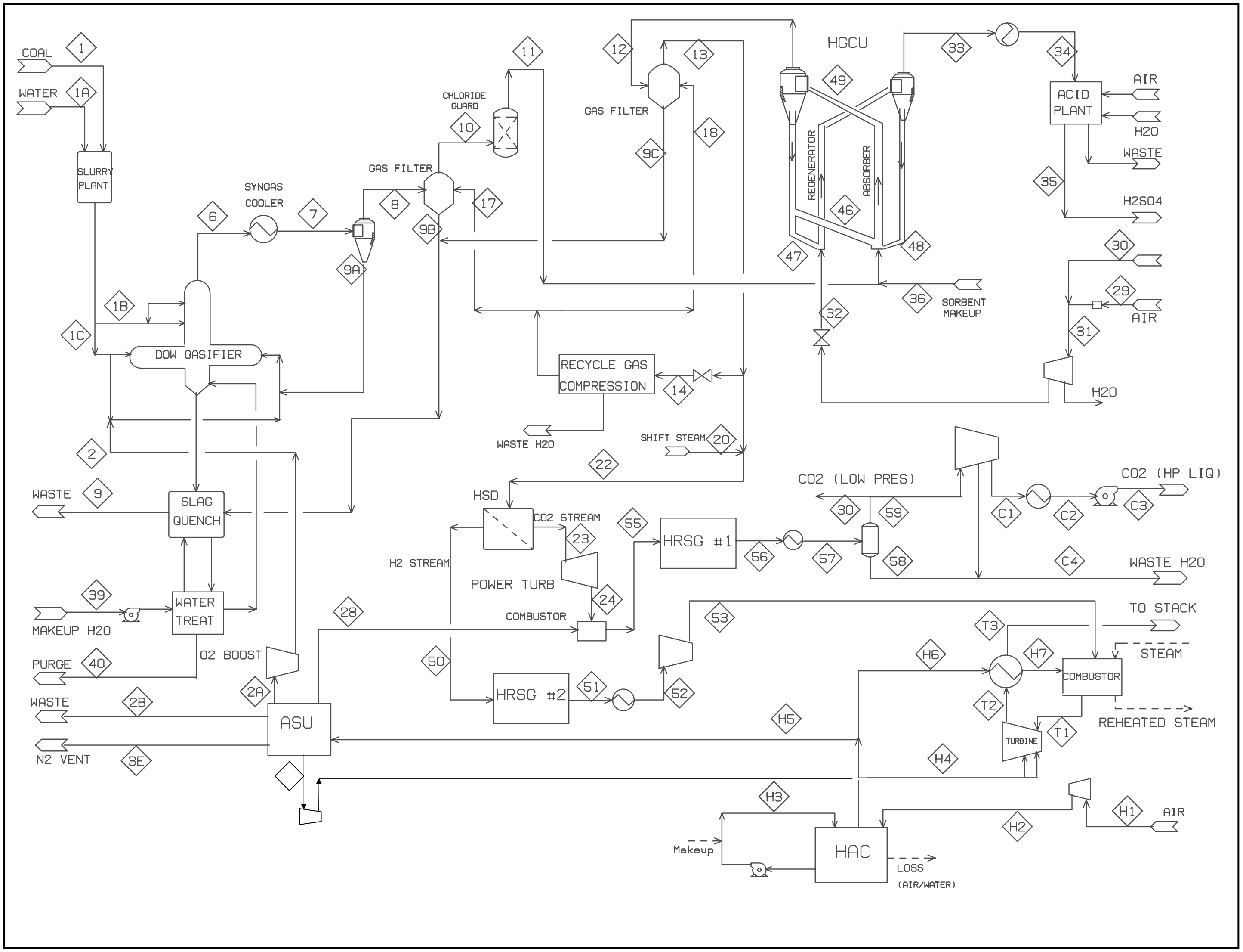


Figure 16. Case 4 - Coal Syngas HAC – with CO_2 Capture

Case 4

HYDRAULIC AIR COMPRESSION CYCLE - COAL SYNGAS - CO_2 SEQUESTRATION

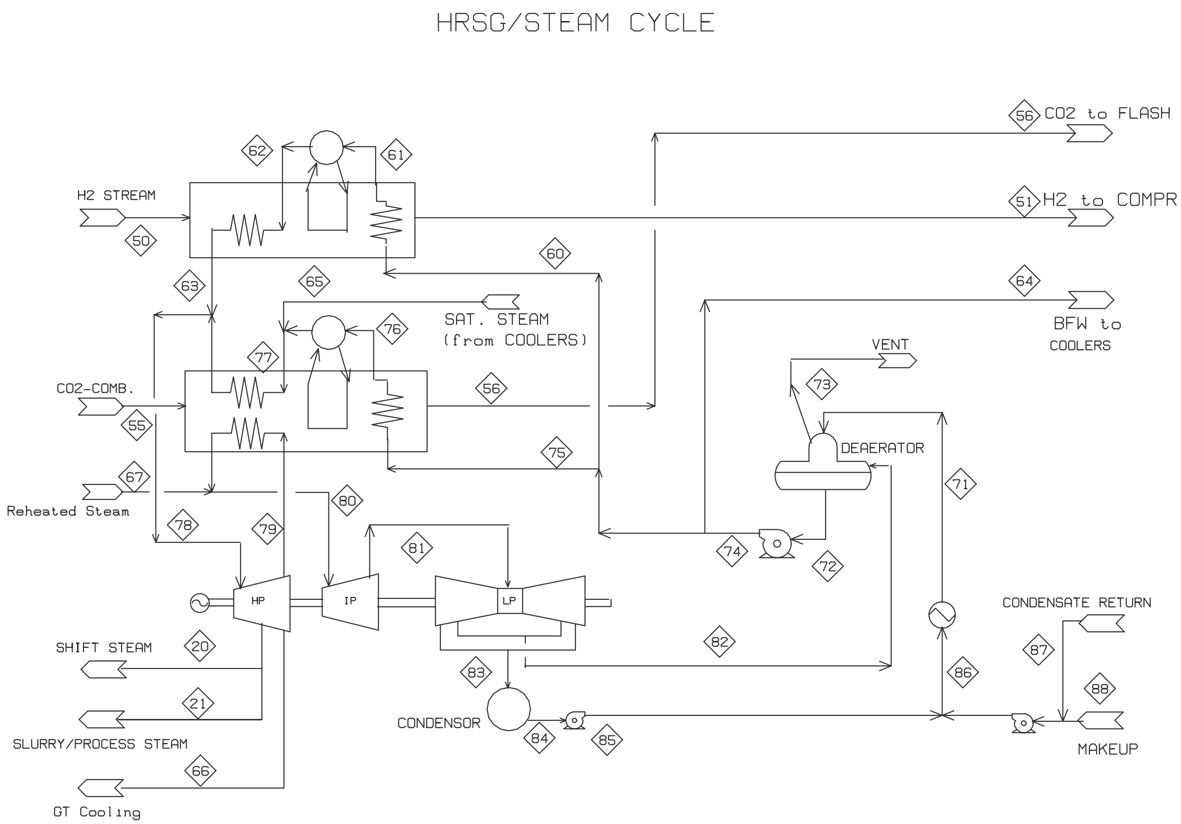


Figure 17. Case 4 - Steam Cycle

II-1.4 Hydraulic Air Compression Cycle (HAC) – Summary

In Table 8, the simulation cases are summarized with the performance and the power listed for major process areas. The overall process efficiencies obtained for all cases do not approach the goals of the Vision 21 program and are lower when compared with reference cases.

The use of the HAC module requires from 170 – 202 MW due primarily for water pumps and varies with the case's air requirement. The air required for the coal cases is higher since the HAC supplies both the gas turbine combustor and the ASU. The HAC power requirements are somewhat less than the original air compressor (> 240 MW) that has been assumed to be removed from the gas turbine. For all cases a recuperator preheats the high pressure air with the turbine exhaust as part of the HAC module resulting in the loss or major reduction of the power generated from steam turbines normally found in the NGCC or IGCC power plants. This offsets the power gained by removing the air compressor. The results in Table 8 indicate net power losses of approximately 30 – 90 MWe when compared with corresponding reference plants.

Inclusion of CO_2 capture lowers the efficiency significantly by 9.4 percentage points for natural gas and by 8.7 percentage points for coal. The large penalty for the natural gas case is directly related to the poor performance inherit in removing CO_2 from the flue gas stream. The compression power (compression to 2100 psia) and the amine power (inlet flue gas blower, included in MISC/AUX in Table 8) requirements significantly reduce the net power generated. Removing CO_2 in the coal case was based on treating the coal syngas by a membrane reactor system (an advanced technology presently in the research stage of development) that produces a H_2 rich fuel stream and a CO_2 rich stream. This case required an increase in coal flowrate compared to the case without CO_2 capture to obtain sufficient fuel to obtain the same turbine expansion power. Additionally, more CO_2 is produced using the coal fueled process compared to the natural gas fueled process. This is reflected in power requirements for the CO_2 compression section and the MISC/AUX section shown in Table 7.

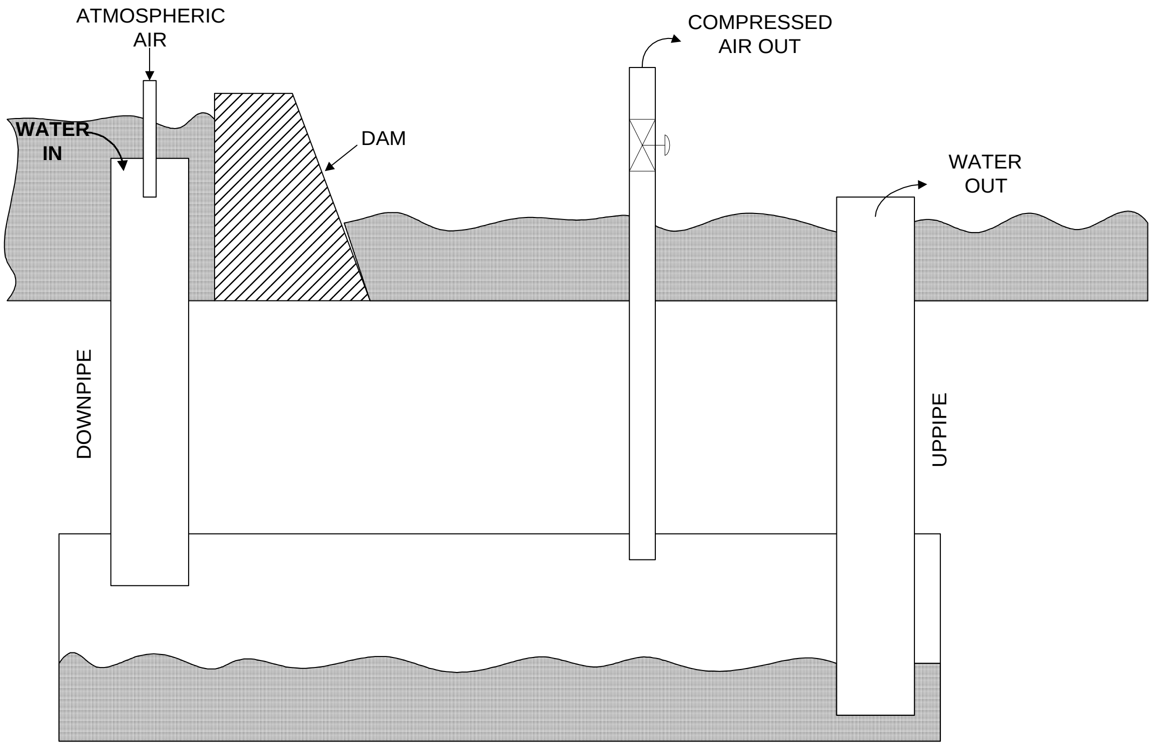
The cost analysis included process contingencies of 25% for the HAC section and 50% for the HSD section to reflect that these two areas represent technology that is in a development stage and not commercially available. Additionally, a 25% contingency was used in estimating the costs for the modified turbine expander/combustor required for these cases. The water pumps costs are also very significant and were based on using the ICARUS cost estimating package and on information obtained from a vendor [18]. The COE spreadsheets are provided in Appendix B.

Table 7. Summary of HAC Cases - with/without CO_2 Sequestration

CASE	1	2	3	4
FUEL	**CH4**	**CH4**	**COAL**	**COAL**
CO_2 CAPTURE	**NO**	**YES**	**NO**	**YES**
HHV %	48.1	39.6	42.3	33.9
LHV %	53.2	43.8	43.8	35.2
NET POWER MWe	323.5	300.2	325.9	312.4
work/power MWe:				
Gas Turbine Exp	494.8	498.8	499.1	501.7
CO_2 Expander	-	-	-	58.5
Steam Turbines	6.1	-	30.9	47.6
HAC	170.7	170.7	184.1	204.1
CO_2 Separation	-	11.4	-	28.2
H_2 Compression	-	-	-	26.1
MISC / AUX	6.6	16.5	20	36.9

II-1.5 Hydraulic Air Compression Cycle (HAC) – Open Loop Water System

In the study sponsored by NETL [14], HAC was considered for open loop water systems that could be located at dams or reservoirs. This eliminates a major power requirement for pumps found in the cases considered above based on a closed loop water system. An example from the study shows the following conceptual representation of this HAC module:



SEPARATION TANK

In Table 8, the results that were obtained for the closed loop water HAC cases have been modified to approximately judge what the results would have been for an open loop water system that could exist for a niche market at a dam site. The modifications made were to eliminate the HAC power requirements and obtain an adjusted net power and efficiency. These results were modified further by reducing the net power by the amount of power that would be expected to be generated using the same amount of water in a hydroelectric plant. The results show efficiencies that are about 10 – 13 percentage points (LHV) above the results obtained for the closed loop water systems. Additionally, these modified cases have higher efficiencies when compared to the reference cases by 5 – 8 percentage points. This indicates that the HAC approach for open loop water systems may be advantageous even though it will be a small market due to limited availability of applicable sites.

Table 8. Summary of HAC Cases - modified for open loop water system

CASE	1	2	3	4
FUEL	CH4	CH4	COAL	COAL
CO_2 CAPTURE	NO	YES	NO	YES
Power Adjustments (MWe) - for open (no water return) HAC				
gross power	330.1	306.3	335.9	322.1
hac cpr	2.1	2.1	2.2	2.5
hac pump	168.6	168.6	182.0	201.6
adjusted gross power	498.7	474.9	517.9	523.7
adjusted aux	10.0	9.5	15.5	15.7
adjusted net power	488.8	465.4	502.4	508.0
Adjusted Efficiency (hydroelectric power reduction not included)				
- HHV %	72.6	61.4	65.2	55.1
- LHV %	80.4	68.0	67.6	57.2
Calculation of Hydroelectric Power (same water usage & head as HAC)				
HAC Water Usage (M3/sec)	591.4	591.4	638.3	707.2
Hydraulic Head (M)	25.0	25.0	25.0	25.0
Water Power (MWe)	145.0	145.0	156.5	173.4
Hyroelectric Power (MWe)	87.2	87.2	94.2	104.3
http://www.iclei.org/efacts/hydroele.htm		POWER (kW) = 5.9 x FLOW x HEAD		
		(60% of water power)		
Adjusted Net Power (includes hydroelectric reduction)				
- MWe	401.5	378.2	408.2	403.7
Adjusted Efficiency (includes hydroelectric reduction)				
- HHV %	59.7	49.9	53.0	43.8
- LHV %	66.0	55.2	54.9	45.4
Adjusted Total Capital Requirement $/KW	273.0	612.1	881.4	1449.6
Adjusted COE $ / MW-hr	25.8	38.0	28.5	41.8
Efficiency - non HAC system reference cases				
- LHV %	57.9	49.9	46.7	40.1
delta (HAC and Non-HAC)	8.1	5.3	8.2	5.3

II-2. CLEAN ENERGY SYSTEMS (CES) – ROCKET ENGINE STEAM CYCLE

Clean Energy Systems (CES) [19] has proposed an electric power generation system based on using fossil fuels such as natural gas, coal syngas (cleaned of sulfur), and coal-bed methane. The system, termed Zero Emission Steam Technology (ZEST) uses a combustion process that burns nearly pure oxygen with a hydrocarbon fuel under stoichiometric conditions. This essentially eliminates the formation of oxides of nitrogen and produces a product that contains primarily carbon dioxide and steam. In the CES process, Figure 18, a gas generator injected with a recycled high pressure water/steam mixture is fired with a fossil fuel using high pressure oxygen. The exhaust powers a high pressure/high temperature turbine (HPT). The HPT exit stream is used for water/steam heating and sent to a combustor reheater to increase the temperature to levels expected for advanced combustion turbines (i.e. >2500 ^{o}F). The remaining turbine sections may have intermediate feed water heaters before the exhaust stream (approximately 90% H_2O, 10% CO_2) enters a partial condenser and then a condenser / CO_2 recovery section.

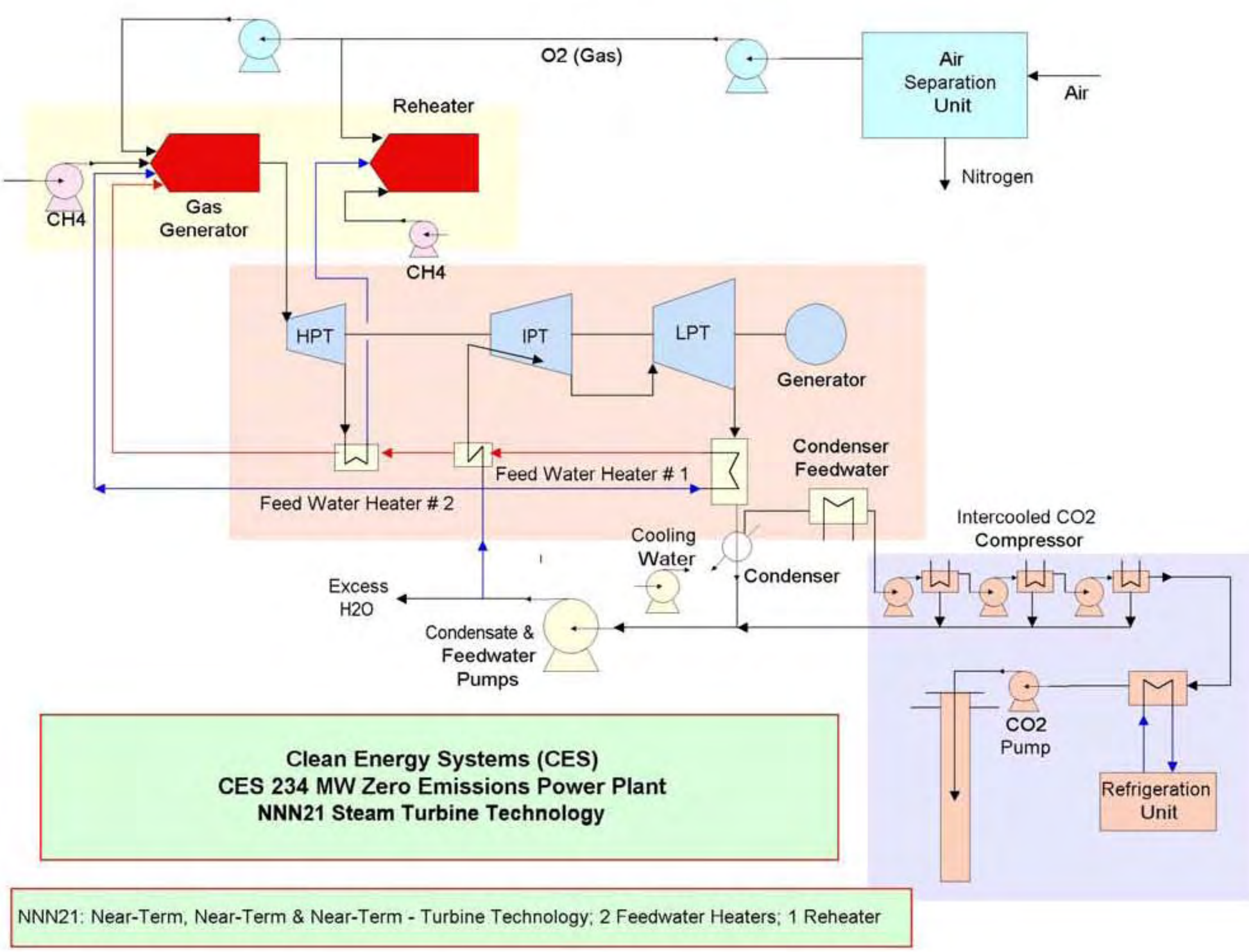


Figure 18. CES Process (provided by CES – version NNN21).

Current overall efficiency projections (LHV basis) provided by CES to NETL [20] for natural gas systems ranged from 44 % - 62 % and recently published results for coal systems [21] ranged from 32% to 44%. The higher values assume turbine technology developments that allow for inlet temperatures of 3200 ^{o}F, low last turbine stage exhausts (0.65 psia) and the use of oxygen generation using membranes.

Aspen Plus® simulations were developed based on flow diagrams provided by CES (Larry Hoffman, CES) for both a natural gas system and a coal system. Emissions for NOx were considered negligible since high purity oxygen (99.5%) was used in the simulations. CO_2 was estimated from the ASPEN simulations and considered sequestered as a liquid using a CO_2 compression scheme.

The COE estimates were developed using information provided by CES in reports and communications to NETL. [22]. Footprint (battery limits) were developed for the natural gas case based on the ASU plant being the major equipment section. The coal case used this approach and the footprint determined for a Destec IGCC plant.

In Table 9, results obtained are listed:

Table 9. CES – Rocket Engine Systems

POWER SYSTEM	ROCKET ENGINE (CES)	
Generation Cycle	CES Natural Gas (gas generator) (CO2 CAPTURE)	CES / COAL (gas generator) Destec HP (E-Gas) HGCU (CO2 CAPTURE)
Net Pow er MWe	398.4	406.2
Net Plant Efficiency	48.27	41.4
% LHV		
Total Capital Requirement	975	1768
$ / KW		
Cost of Electricity	49.2	49.3
Constant $ / MW-hr		
NOx emissions	NEG	NEG
lb/MW-hr		
Sox emissions	---	0.044
lb/MW-hr		
CO2 Production		
lb/MW-hr		
a) Emitted to atmosphere	---	---
b) Sequesterable	901	1702
Footprint (battery limits)	825	1458
sq ft/MW		

II-2.1 Clean Energy Systems (CES) - Natural Gas System

An Aspen Plus® simulation was developed for the natural gas fueled CES proposed process as shown in Figure 19. The key process sections are:

- Cryogenic ASU – to reduce the amount of nitrogen in the turbine exhaust stream that enters the downstream condenser section, a high purity low pressure oxygen plant that is commercially available and produces a high purity oxygen (99.5%, volume) product is used. The power requirements were estimated as 359.4 kW / (lb/sec O_2).

- Oxygen / Fuel Compressors – Two multistage intercooled oxygen compressors were used, a six stage unit supplies oxygen at 2500 psia to the gas generator and a three stage unit supplies oxygen at 420 psia to the reheat combustor. A two stage compressor is used for the fuel stream supplied to the gas generator.

- Gas Generator – this section was represented using an ASPEN reactor model. The input streams consisted of natural gas (represented as methane), high pressure steam and high pressure water. The cost estimate was made using information furnished in CES reports with a process contingency of 25% used.

- High Pressure Turbine / Steam generator – Power was generated using a HPT with the exhaust used to generate steam before being sent to the reheat combustor.

- Reheater – oxygen combustor that reheats the process stream using additional methane fuel to raise the temperature to 2600 ^{o}F before entering a final series of turbine expanders. Again the cost estimate was based on CES information.

- Intermediate/Low Pressure Turbines – The gas stream has a composition of about 90% steam, 10 % CO_2 with small amounts of nitrogen/argon impurities. Thermodynamic properties used were based on an equation of state for highly non-ideal system (Schwartzentruber-Renon) to accurately represent this stream. Costs for all turbines (HPT,IPT,LPT) were based on using the ICARUS costing software. A 25% process contingency was used.

- Heat Recovery / Condenser – the process stream at 2.1 psia enters a heat exchanger used to generate steam before entering the condenser. Depending on the temperature of available cooling water, different amounts of water can be condensed out. Based on cooling the process stream to 100 ^{o}F, approximately 88% of the water is condensed out for recycling.

- CO_2 Compression Process - An intercooled seven stage compression process was used to eliminate any remaining water and to produce a CO_2 product stream at 2100 psia which was cooled to 100 ^{o}F and then pumped to 3000 psia for storage. An ICARUS estimate for this section results in a cost of 31500 K$ or approximately $1000/kW. (based on the compressor power). The first stage compressor because of the low inlet pressure (1.9 psia) is beyond most available single train equipment and will require several trains of equipment.

The Aspen Plus® simulation and the cost estimate yielded the results listed in Table 9 above. The overall process efficiency of 48.3%, the total capital requirement of $975/kW, and the COE estimate of 49.2 $/MW-Hr indicate poorer performance when compared with the reference NGCC plant that included CO_2 capture. (i.e. 49.9%, 911 $/kW , 46.4 $/MW-Hr) . The oxygen plant, oxygen compressors and CO_2 section account for over 55% of the equipment costs. CES has efficiency estimates that appear to be approximately 2 percentage points higher for these conditions and higher estimates based on using conditions that appear to be either questionable such as 3200 ^oF turbine inlet temperatures or low exhaust pressures of 0.65 psia which will increase the cost of the CO_2 compression process. Additional simulation results are provided in Appendix A and the COE cost spreadsheet is provided in Appendix B.

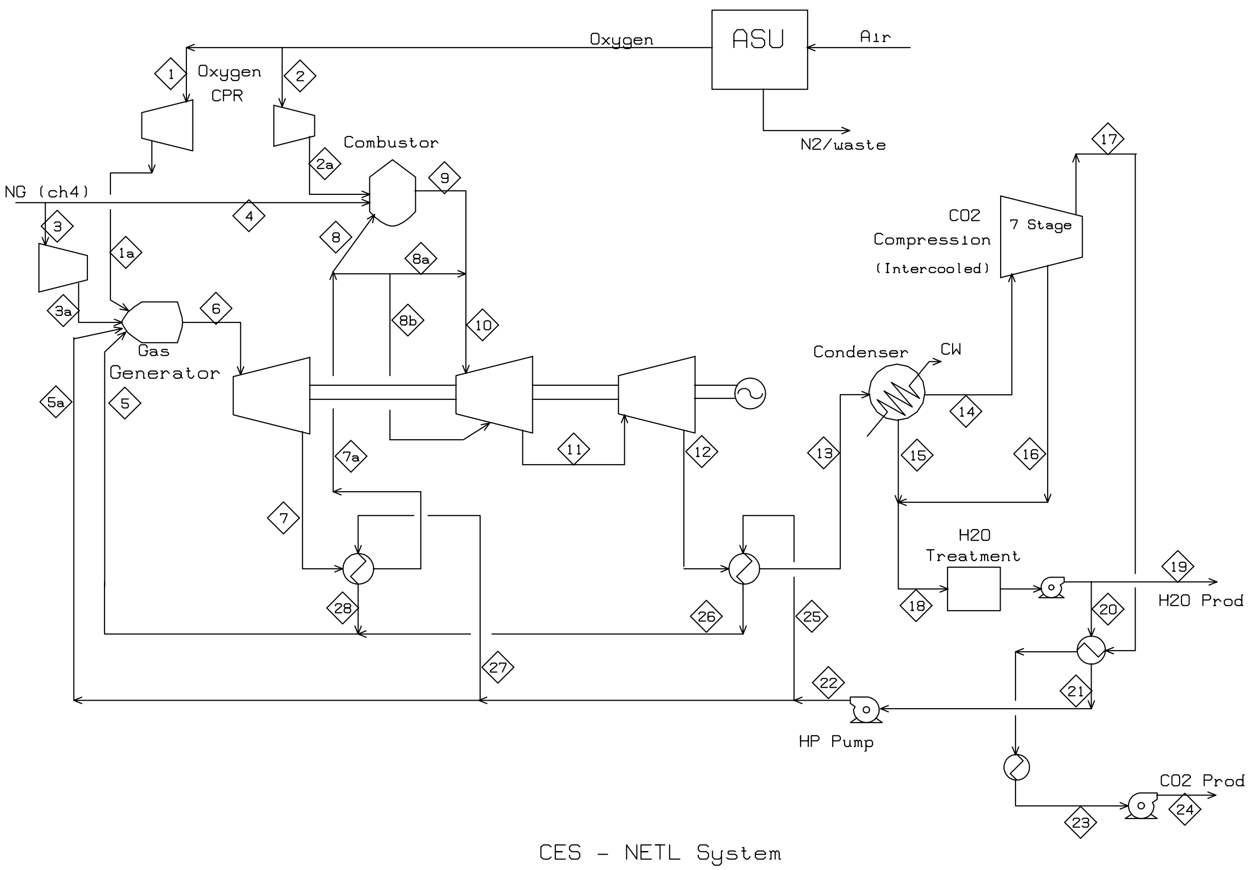


Figure 19. CES – Rocket Engine Steam Cycle – 400 MWe – Natural Gas

II-2.2 Clean Energy Systems (CES) - Coal Syngas System

An Aspen Plus® simulation, Figure 20, was developed to evaluate the performance and cost of the proposed CES process when fueled with a coal syngas. The representation for the natural gas system was combined with sections of a Destec IGCC process based on HGCU. The major sections included were:

- Cryogenic ASU – the same high oxygen purity system was used and the capacity adjusted to provide oxygen for the gasification area.

- Destec Gasification / Syngas Cooler – the gasifier was operated at approximately 1000 psia. The higher pressure gasifier was used to provide the highest pressure deemed feasible for the fuel stream being generated for the CES gas generator. The syngas cooler was integrated into the CES section to serve as a steam superheater. The coal flowrate used was adjusted to obtain a net power output of approximately 400 MWe.

- Coal Syngas Cleanup – the gasifier/syngas cooler as in the reference IGCC case was followed with cyclones for particulate removal and a chloride guard bed . The transport desulfurizer / acid plant approach were used to remove H_2S and COS from the syngas stream. Depending on the requirements of the CES process this may have to be augmented with additional guard bed to further reduce the sulfur level. The gas stream from the HGCU regenerator enters a heat exchanger before proceeding to the acid plant. This exchanger also was integrated into the CES process to superheat steam.

- CES process - Includes the same sections as described in the previous sections with the feed water heaters adjusted to include heat recovery from the gasifier syngas cooler and from the cooler that precedes the acid plant. Due to the use of the coal syngas instead of methane, the amount of CO_2 generated approximately doubles. This is reflected in a higher CO_2 percentage in the low pressure turbine exhaust of about 18% versus 10% for the natural gas case.

The ASPEN Plus simulation and the cost estimate yielded the results listed in Table 9 above. A comparison with the Destec reference case that included CO_2 capture indicated slightly better performance: (reference case shown in brackets)

Overall Process Efficiency	:	41.4%	[40.1%] ,
Total Capital Cost $/kW	:	1768	[1897] ,
COE $/MW-Hr	:	49.2	[46.4].

CES has efficiency estimates that were based on using a Texaco gasification process that appear approximately the same as these results for the process efficiency. Details of these two simulations have been provided to CES (Larry Hoffman) and are provided in Appendix A and Appendix B.

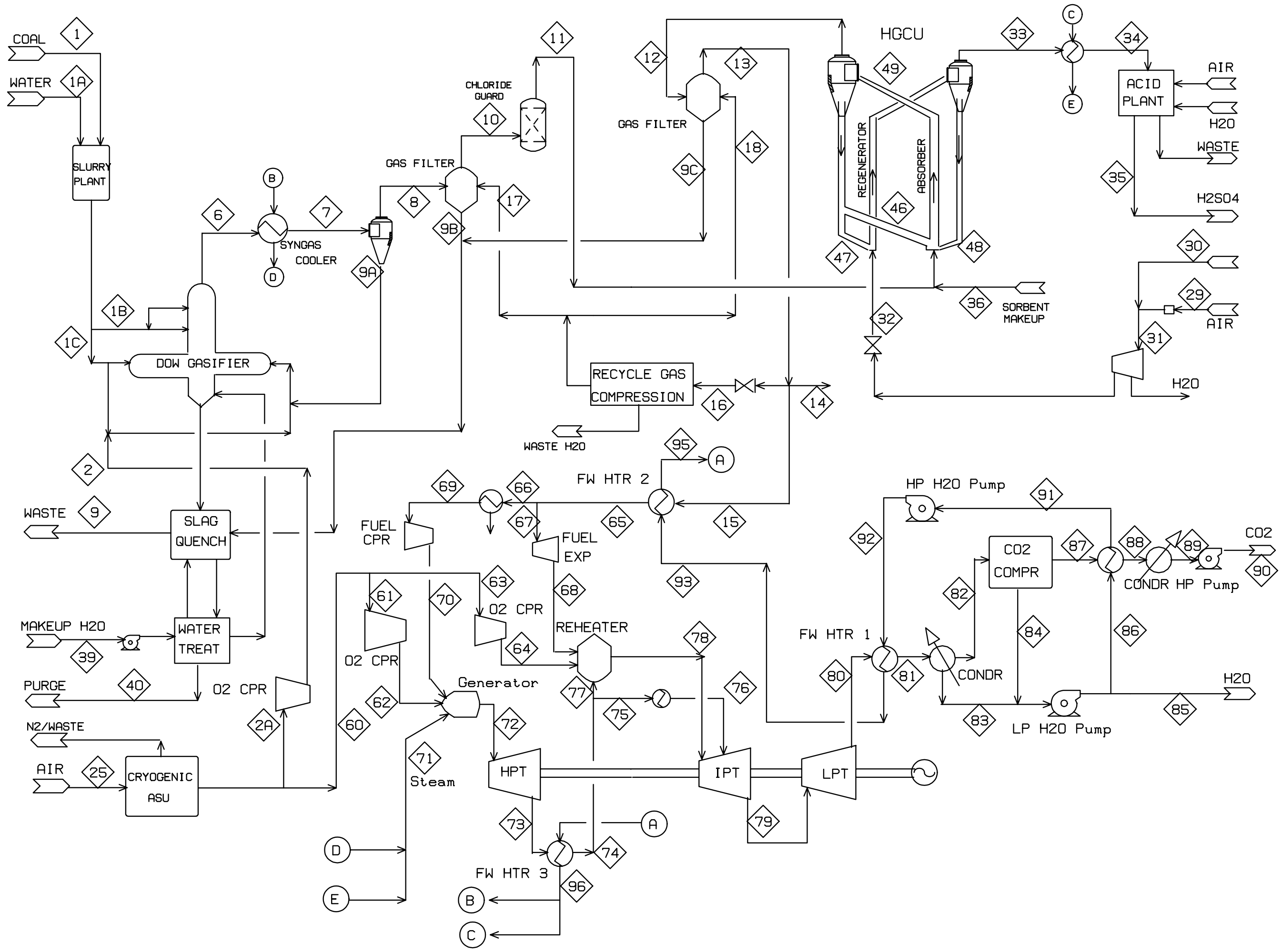


Figure 20. CES – Rocket Engine Steam Cycle – 406 MWe – Coal Syngas.

II-2.3 Clean Energy Systems (CES) - Summary

The CES Rocket Engine Steam cycles based on either natural gas or coal syngas do not appear to be able to reach the performance levels of the Vision 21 program. Additionally, considerable effort both in research and funding is anticipated to develop the gas generator and the ultra high pressure/temperature turbines. The oxygen combustion process envisioned increases the oxygen required significantly when compared with an oxygen blown IGCC process. This leads to some projected improvement in performance and cost if the cryogenic ASU is replaced with a membrane process (ITM or OTM) for oxygen production. Another problem area is the large compression cost for the first stage of the carbon dioxide recovery system resulting from the low exhaust pressure of 0.65 – 2.1 proposed by CES. The Aspen Plus® simulations also assumed that both the gas generator and reheater combustor could combust the fuel using near stoichometric amounts of oxygen. Some consideration may be warranted to increasing the low pressure exhaust temperature to near atmospheric levels, recovering energy by generating steam for injection and then condensing the water out and starting the carbon dioxide compression from this higher pressure point.

II-3. HYDROGEN TURBINE CYCLES

As an alternate approach for achieving CO_2 capture, two cases were developed using a power cycle based on the gas turbine being fueled with hydrogen. High pressure air supplied by the compressor section was still used in the combustor. The hydrogen stream in the first case is based on using steam reforming of natural gas (methane used for simulations) and for the second case on using an IGCC process that uses coal. The results from the Aspen Plus® simulations and the COE analysis are shown in Table 10. In both cases, the gas turbine fueled by hydrogen produces 269 MWe of power. The CO_2 compression section power requirements are (as expected) significantly different (13.5 MWe in case 1 versus 31.6 MWe in case 2) due to the coal case generating more than double the amount of CO_2 as for the natural gas case. Flow diagrams are provided with material and energy balance summaries in Appendix A and the COE results are in Appendix B. For both cases, the hydrogen produced probably is bettered used as a chemical product rather than for power generation. Table 10 indicates both a process efficiency based on the amount of methane required in the steam reformer and based on the amount of hydrogen used. An alternate process that uses less methane would result in an efficiency between these two values.

Table 10. Hydrogen Turbine Power Cycles.

POWER SYSTEM	HYDROGEN TURBINE (HT)	
Generation Cycle	HT (H2 FROM SMR) (CO2 CAPTURE)	HT / COAL Destec HP (E-Gas) HGCU (CO2 CAPTURE)
Net Power MWe	413.1	375.3
Net Plant Efficiency	64.4 (H2)	38
% LHV	42.9 (NG)	
Total Capital Requirement	1323	1909
$ / KW		
Cost of Electricity	63.5	53.6
Constant $ / MW-hr		
NOx emissions	0.161	0.177
lb/MW-hr		
Sox emissions	---	0.046
lb/MW-hr		
CO2 Production		
lb/MW-hr		
a) Emitted to atmosphere	---	---
b) Sequesterable	719	1731
Footprint (battery limits)	472	1445
sq ft/MW		

II-3.1 Hydrogen Turbine Cycles – Natural Gas Case

This case was developed by modifying the NGCC reference simulation (see I-2.1) to use hydrogen in place of natural gas as the fuel for the gas turbine. The required hydrogen was assumed to be supplied by a steam methane reformer / hydrogen purification process. (commercially available process [23]). The hydrogen purification uses pressure swing absorption and the CO_2 is recovered by extending the process to include a vacuum swing absorption step. The CO_2 captured was then compressed to a high pressure (2100 psia) to enable sequestration as a liquid product. (The economic analysis does not assume a value for this product or include a transportation charge for disposal.) The steam generated in the SMR was integrated into the combined cycle process to recover additional power. The net power generated was calculated based on the simulation results for the gas turbine, steam turbine, CO_2 captured and a literature estimate for the SMR process. The process efficiency was calculated using the net power generated using both the hydrogen used (in the gas turbine) and the methane used (in the SMR) to generate this hydrogen.

Emissions were calculated for CO_2 based on the natural gas (methane) used in the SMR as fuel. The NOx was estimated based on 9 ppmv for the gas turbine section added to an estimate for the SMR plant.

The COE cost analysis relied on the NGCC reference case augmented by the cost of the SMR plant and the CO_2 compression section. The footprint (battery limits) of the NGCC reference case was similarly increased by an estimate for the SMR and CO_2 recovery equipment. For costing, the overall plant site was considered to cover 100 acres.

Figure 21 illustrates the simulation model representation, Appendix A contains the material and energy balance summaries and Appendix B contains the COE spreadsheet summary.

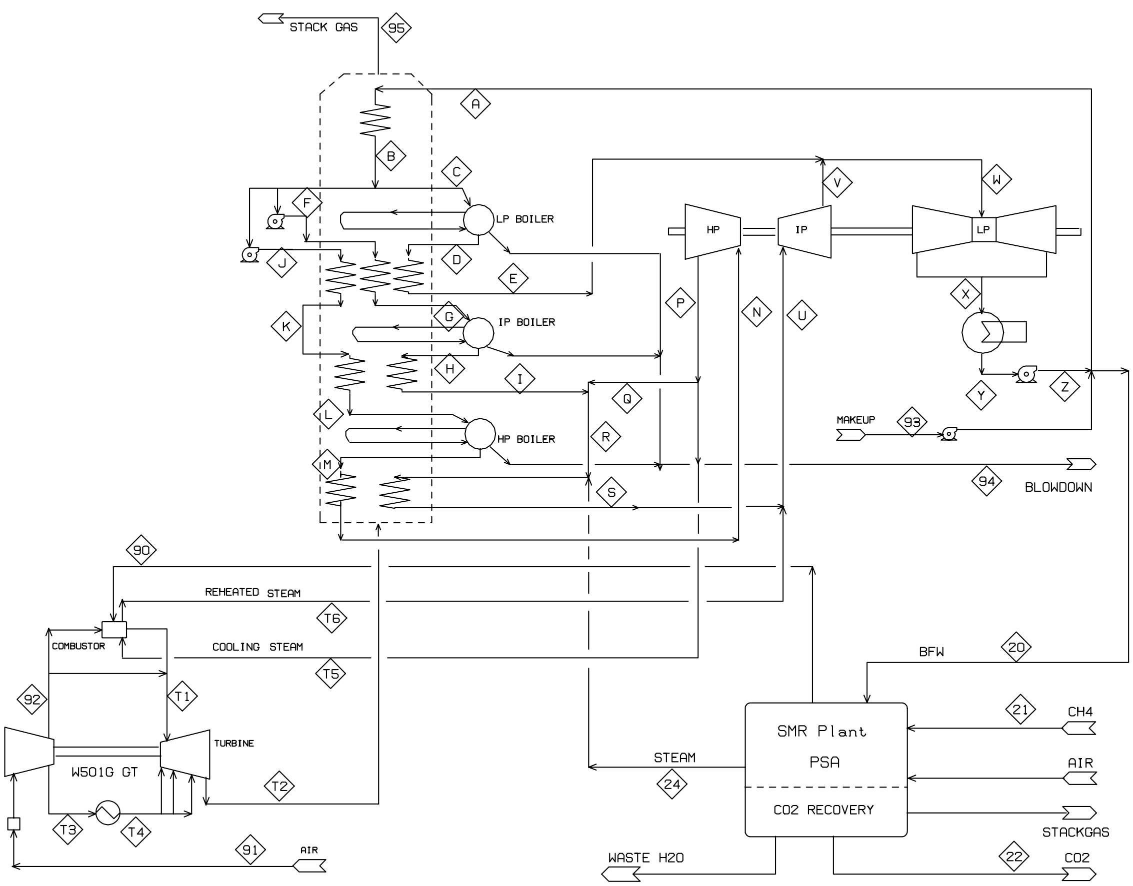


Figure 21. Hydrogen Turbine Cycle – Natural Gas

II-3.2 Hydrogen Turbine Cycles – Coal Case

The Aspen Plus® simulation model was developed by modifying the simulation developed and described above (see section II-1.3) for the Hydraulic Air Compression (HAC) case with CO_2 capture. The major plant sections: high pressure Destec Gasifier, ASU, HGCU, Acid plant, HSD, H_2 stream HRSG, CO_2 stream HRSG , CO_2 compression, steam turbines are retained from the HAC case. The necessary changes are:

- the insertion of a section for the hydrogen powered "G" gas turbine , HRSG and steam cycle to replace the hydraulic compression/recuperator sections in the HAC case. This is the section equivalent to the above natural gas case (see II-3.1, Figure 21).

The resulting process is shown in Figure 22 (similar to Figures 16, 17). This case indicates a decrease in process efficiency to 38 % (LHV) compared to the 42.9% determined for the natural gas fueled hydrogen turbine cycle. Again as a power plant this case appears to have no hope of meeting Vision 21 goals. Alternately, the gas turbine and steam cycle sections can be omitted and the process viewed as producing hydrogen and power. The heating value of the hydrogen (100%) is then used to calculate a combined heat and power efficiency for which the Vision 21 goal is 85 – 90% (HHV) based on coal fuel [24]. The present case based on a hydrogen production (45384 lbs/hr) and the remaining net power would yield the following:

CHP eff. (HHV) = 100% * (H_2 heating value + net power*3414) / (coal heating value)

= 79.4%

This is again below the Vision 21 objectives.

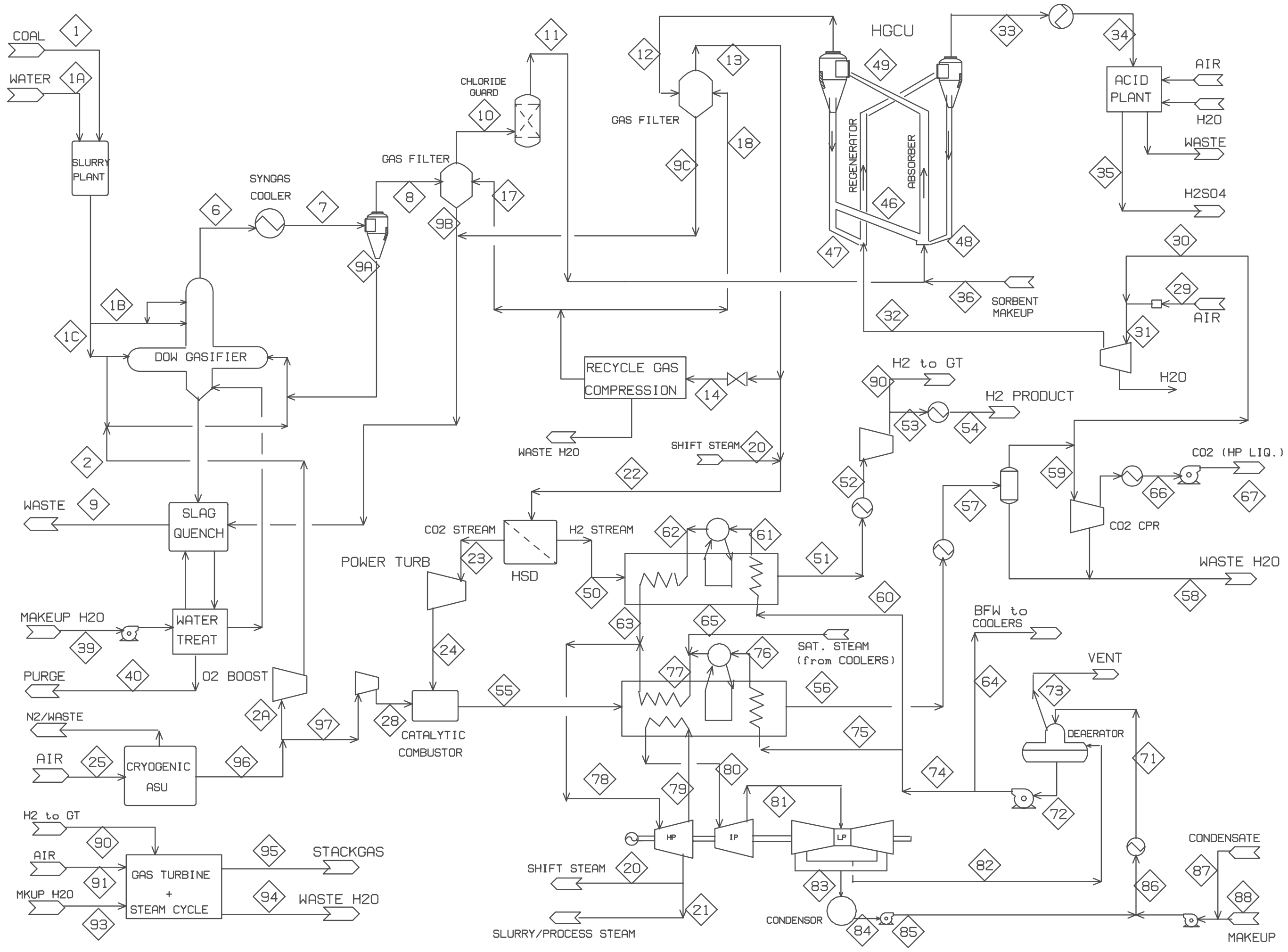


Figure 22. Hydrogen Turbine Cycle – Coal

II-3.3 Hydrogen Turbine Cycles – Summary

The hydrogen turbine cycles as summarized in Table 10 have poorer performance and higher cost when compared with reference cases. The natural gas fueled case has an efficiency of 42.9% (LHV) and a COE of 61.2 $/MW-Hr. The NGCC reference case that uses an amine process for CO_2 capture has a higher efficiency of 49.9% and a COE of 46.4. The coal fueled case efficiency of 38.0% is approximately the same as the Destec/CGCU reference case results of 40.1% .

An alternate hydrogen turbine cycle has been proposed for coal gasification systems that rely on hydrogen combustion with oxygen [25]. Steam is injected in the combustors in a manner that is somewhat similar to the CES systems described in II-2. The coal syngas generated by gasification is shifted and sulfur compounds and CO_2 removed using the RECTISOL absorption process and sulfur recovered in a CLAUS/SCOT section. The hydrogen produced is split between a high pressure combustor and a reheat combustor between two turbine expander sections. A HRSG is used to generate steam before the flue gas (essentially steam) is expanded in a low pressure turbine section. The process projects efficiencies of approximately 50% (HHV) which includes CO_2 compression to 80 bar (1160 psia).

II-4. HYBRID - TURBINE / FUEL CELL CYCLES

A Hybrid power system configured as a combined cycle based on using a high temperature Fuel Cell and a Gas Turbine holds promise for approaching the efficiency goals of the Vision 21 program. DOE is currently sponsoring a number of programs both to develop fuel cells, to compare different hybrid concepts and to evaluate related technical issues [26]. Major hurdles also included reducing the cost and size of the fuel cell modules to make hybrid systems available for generating electrical power in commercial power plant sizes > 100 MWe. The current report considers the systems summarized in Table 11 and are based on using Solid Oxide Fuel Cells (SOFC). The efficiencies shown are based on using currently available components and projected performance for the SOFC modules. Modest improvements in turbine and/or fuel cell performance would probably result in these systems obtaining the Vision 21 goals of 75% (LHV) for natural gas systems and 60% (HHV) for coal systems.

Table 11. Hybrid Turbine/Fuel Cell

POWER SYSTEM	HYBRID CYCLE (HYB)			
Generation Cycle	Natural Gas Hybrid Turbine-SOFC Cycle	HYB / COAL Destec (E-Gas) HGCU "G" GT / SOFC (NO CO2 CAPTURE)	HYB / COAL Destec HP (E-Gas) HGCU / HSD "G" GT / SOFC (CO2 CAPTURE)	HYB / COAL Destec (E-Gas) OTM / CGCU "G" GT / SOFC (NO CO2 CAPTURE)
Net Pow er MWe	19	643.6	754.6	675.2
Net Plant Efficiency	67.3	56.4	49.7	57
% LHV				
Total Capital Requirement	1476	1508	1822	1340
$ / KW				
Cost of Electricity	53.4	41.1	48.8	38
Constant $ / MW-hr				
NOx emissions	0.0132	0.107	0.093	0.101
lb/MW-hr				
Sox emissions	---	0.005	0.004	0.014
lb/MW-hr				
CO2 Production				
lb/MW-hr				
a) Emitted to atmosphere	661	1254	101	1237
b) Sequesterable			1323	
Footprint (battery limits)	1120	1310	1408	1388
sq ft/MW				

II-4.1 Hybrid - Turbine/Fuel Cell Cycles – Natural Gas Case

The results for this case were obtained from a report “Pressurized Solid Oxide Fuel Cycle/Gas Turbine Power System” by Siemens Westinghouse / Rolls-Royce Allison for the DOE. (DE-AC26-98FT40355 , February 2000) [27]. (The reported performance was verified using an Aspen Plus® simulation).

The DOE report describes the development of a conceptual design for a pressurized SOFC/GT power system that was intended to generate 20 MWe with at least 70% efficiency. The system shown, Figure 23, designated the HEFPP system cycle (High Efficiency Fossil Power Plant) integrates an intercooled, recuperated, reheated gas turbine with two SOFC generator stages. One SOFC stage operates at high pressure, and generates power as well as providing all heat needed by the high pressure turbine. The second SOFC generator operates at a lower pressure, generates power, and provides all heat for the low pressure reheat turbine. The system is projected to have an efficiency of 67.3% (LHV).

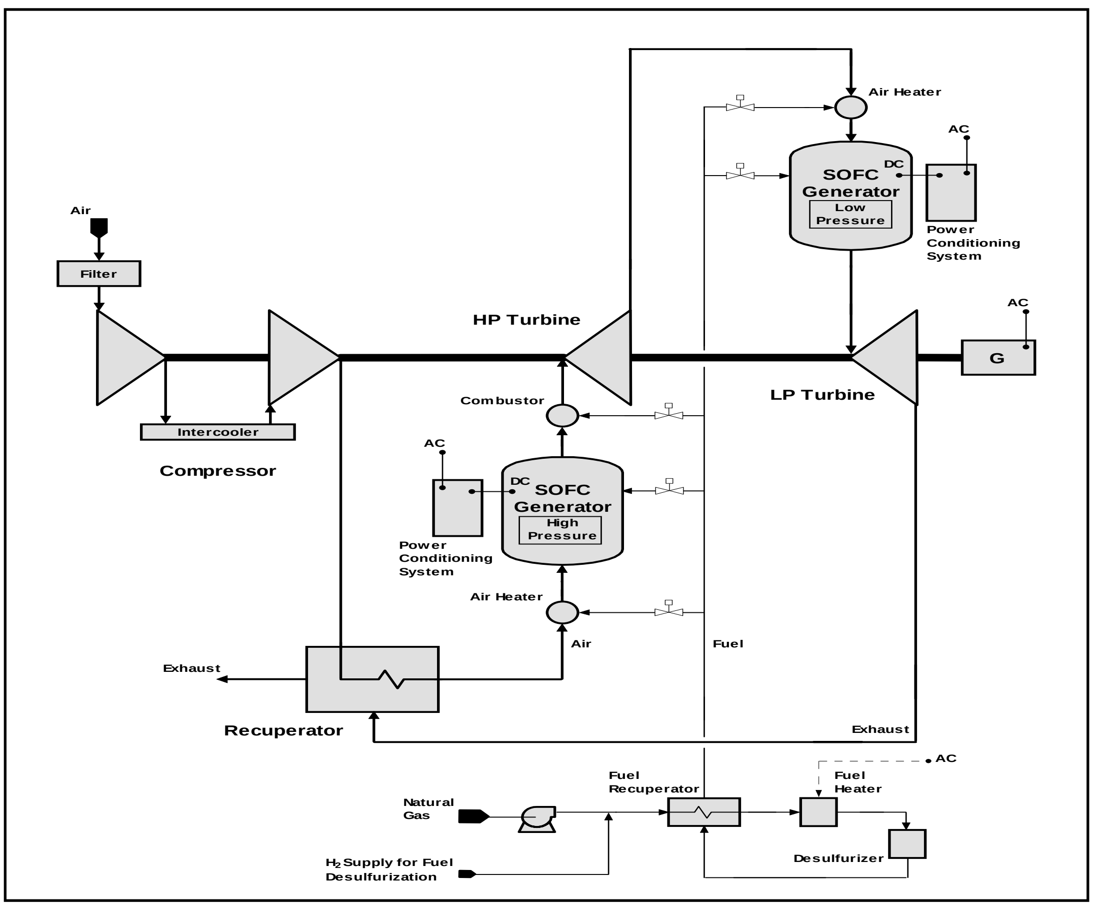


Figure 23. High Efficiency Fossil Power Plant Cycle (HEFPP)

The following design conditions are summarized from the report:

Approximate Power Generation : 15 MWe from SOFC and 4 MWe from Gas Turbine.
Fuel – Methane (96%), Nitrogen (2%), Carbon dioxide (2%), Sulfur (4 ppmv)
Air – inlet flow rate to air compressor = 40 lbs /sec, 59 ^{o}F, 14.7 psia.
Air Compressor – two stages intercooled , overall pressure ratio = 7:1 ,
isentropic efficiency = 86.4%.
Recuperator – preheats high pressure air using LP turbine exhaust to about 1126 ^{o}F.
HP SOFC – operates at exit conditions of about 1600 ^{o}F and 92 psia ,
required fuel inlet sulfur level 0.1 ppmv , 90% fuel utilization.
HP Turbine – isentropic efficiency = 90.7 % , inlet temperature = 1600 ^{o}F.
LP SOFC - inlet conditions of 46 psia and 1300 ^{o}F , exhaust at 40 psia and 1600 ^{o}F,
90% fuel utilization.
LP Turbine - exhaust at 1197 ^{o}F and 15.5 psia, isentropic efficiency = 91.3%.

Emissions - CO_2 = 661 lbs / MW-hr , NOx 0.013228 lbs / MW-hr

The Cost Estimate developed was based on the following changes from the report which were made for consistency with other COE estimates:

Plant Costs - adjusted from 1998 basis to first quarter 2002 basis
Fuel Costs – adjusted from \$3.0 / MMBU to \$3.2 / MMBTU.
Annual Operating Capacity Factor – adjusted from 92% to 85%

The following costs were modified from the report to the values shown below :

	\$ / KWe (installed Capital Cost)
SOFC Equipment	
- Generator	486
- Power Conditioning	110
Gas Turbine Equipment	218
BOP	267
Site Prep, M & E	72
Overhead and Profit	300
Spare parts, startup, & land	23
Total Capital Requirement	\$1476 / KWe

Several battery limits designs were proposed that ranged from 0.5 – 0.6 acres. The battery limits are dominated by the SOFC requirements. Siemens Westinghouse / Rolls-Royce Allison project that an optimized system can obtain an efficiency > 70%. It should be noted that the SOFC performance has been estimated with perhaps an optimistic assumption of 90% fuel utilization.

A coal fueled version of this system for a nominal 500 MWe size plant has been previously formulated and projected to have an efficiency of 59% (HHV) [26]. Additional studies are currently being sponsored by NETL for systems based on Shell and Texaco gasifiers. [28]. The results will be available in 2003.

II-4.2 Hybrid - Turbine/Fuel Cell Cycles – Coal Cases

Aspen Plus® simulations were developed for two new cases based on using coal and these results are combined with a third case from an earlier study [29] and summarized in Table 12. All cases were based on using a Destec gasifier, a W501G gas turbine, and a SOFC. The syngas generated was split with 58% sent to the SOFC and the remaining 42% sent to the gas turbine combustor. The coal flowrate was adjusted so that the power produced by the gas turbine was approximately 275 MW for all three cases. Shifting more syngas to the fuel cell will increase efficiency but additionally increase the COE because of the increase in the number of fuel cell modules required. (A capital cost of $800/KW was assumed for the fuel cell section).

Table 12. SUMMARY - SIMULATION FOR COAL SYNGAS HYBRID POWER SYSTEMS

					(POWER IN MWe)					
CASE	CO_2 Capture	GAS CLEANUP	TURBINE FUEL	% SYNGAS TO SOFC	NET POWER	GAS TURBINE	STEAM TURBINE	SOFC	MISC/AUX	EFF % LHV
1	NO	HGCU/ZNO	SYNGAS	58%	643.6	276.1	207.7	221.4	61.5	56.4
2	YES	HGCU/ZNO	H_2	58%	754.6	272.5	226.1	324.1	68.2	49.7
3	NO	CGCU	SYNGAS	58%	675.2	272.7	189.8	254.4	41.8	57

II-4.2.1 Hybrid - Turbine/Fuel Cell Cycles – Coal Cases – Case 1 (No CO_2 Capture)

Case 1 was developed based on making the following modifications to the reference Destec / HGCU case (see Table 2, Figure 8) and does not include CO_2 capture:

- An additional zinc oxide guard bed is added to the HGCU section to reduce the sulfur content of the cleaned fuel gas to acceptable levels for use in the SOFC. (assumed 1-5 ppmv was acceptable and obtainable).

- The SOFC section was added using a previously developed fuel cell model [30]. A fuel utilization of 85% was assumed. The anode and cathode exit streams are combined and the remaining fuel combusted to raise the temperature > 2000 ^{o}F. This stream is used to preheat the cathode inlet stream and then routed to the gas turbine combustor.

- The gas turbine compressor outlet provides 50% of the air required by the ASU and all the air required by the HGCU regenerator as in the reference case. The remaining air is combined with a nitrogen recycle from the ASU and sent to the cathode preheater before entering the fuel cell.

- The cleaned fuel gas is split between 58% entering the fuel cell and 42% sent to the gas turbine combustor.

- The steam cycle design is the same as for the reference case.

In Figure 24, the resulting hybrid GT/SOFC is shown. Appendix A has material and energy balances and Appendix B contains the COE spreadsheet results.

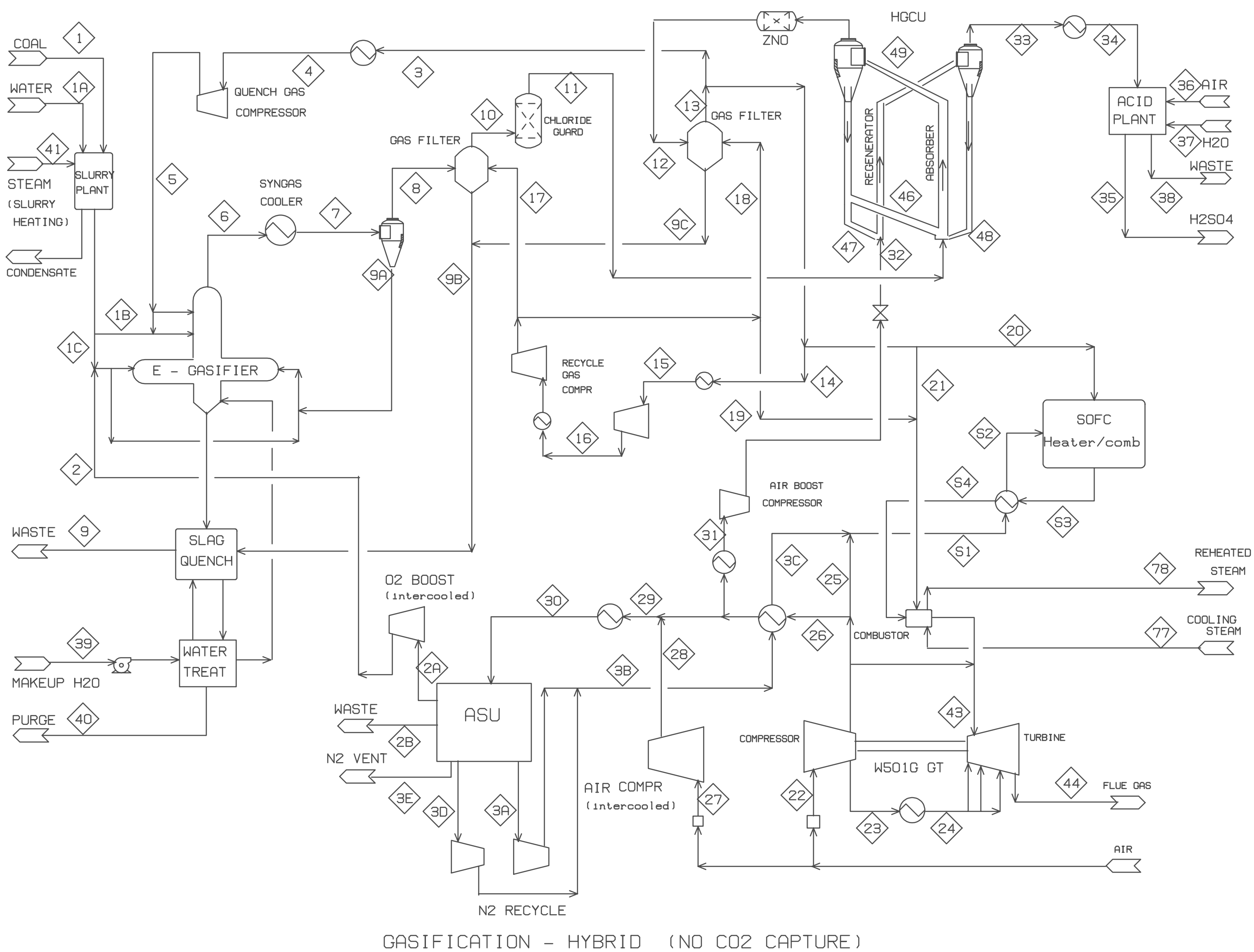


Figure 24. Case 1. Hybrid GT/SOFC – Coal Syngas – No CO_2 Capture

II-4.2.2 Hybrid - Turbine/Fuel Cell Cycles – Coal Cases – Case 2 (CO_2 Capture)

Case 2 was developed based on making the following modifications to the Hydrogen Turbine Coal Cycle case (see Table 10, Figure 22) and includes CO_2 capture:

- An additional zinc oxide guard bed is added to the HGCU section to reduce the sulfur content of the cleaned fuel gas to acceptable levels for use in the SOFC. (assumed 1-5 ppmv was acceptable and obtainable).

- The SOFC section was added using a previously developed fuel cell model [30]. A fuel utilization of 85% was assumed. The cathode exhaust is used to preheat the cathode inlet stream (high pressure air from the gas turbine) and returns to the gas turbine combustor. The anode stream containing unspent fuel is expanded in a power turbine and combined with the CO_2 rich stream from the HSD (hydrogen separation device) and the combined stream enters a catalytic combustor.

- The gas turbine compressor outlet provides 50% of the air required by the ASU and all the air required by the HGCU regenerator. The remaining air is sent to the cathode preheater before entering the fuel cell.

- The cleaned fuel gas is split between 58% entering the fuel cell and 42% sent to the HSD. The fuel sent to the HSD is used to produce hydrogen for the gas turbine.

- Nitrogen is recycled from the ASU to the gas turbine combustor after being preheated in two heat exchangers. The first exchanger uses the hydrogen exhaust stream from the HSD and the second exchanger uses the exhaust from the catalytic combustor.

- Heat Recovery Steam Generators (HRSG) are used to recover available heat in the turbine exhaust, gasifier syngas cooler and the catalytic combustor exhaust. The generated steam is used for power generation and supplying steam for the HSD (shift reaction) and for heating in the slurry plant.

- The CO_2 capture uses the same approach as in the Hydrogen Turbine Case with a high pressure liquid stream produced.

In Figure 25, the resulting hybrid GT/SOFC is shown. In Figure 26, the steam cycle is shown. Appendix A has material and energy balances and Appendix B contains the COE spreadsheet results. As in Case1, the efficiency will improve as more fuel is sent directly to the fuel cell. The fuel split assumed (58% to the fuel cell) was made due to the high capital cost ($800/KW) used for the SOFC modules and the desire to use the modified W501G gas turbine.

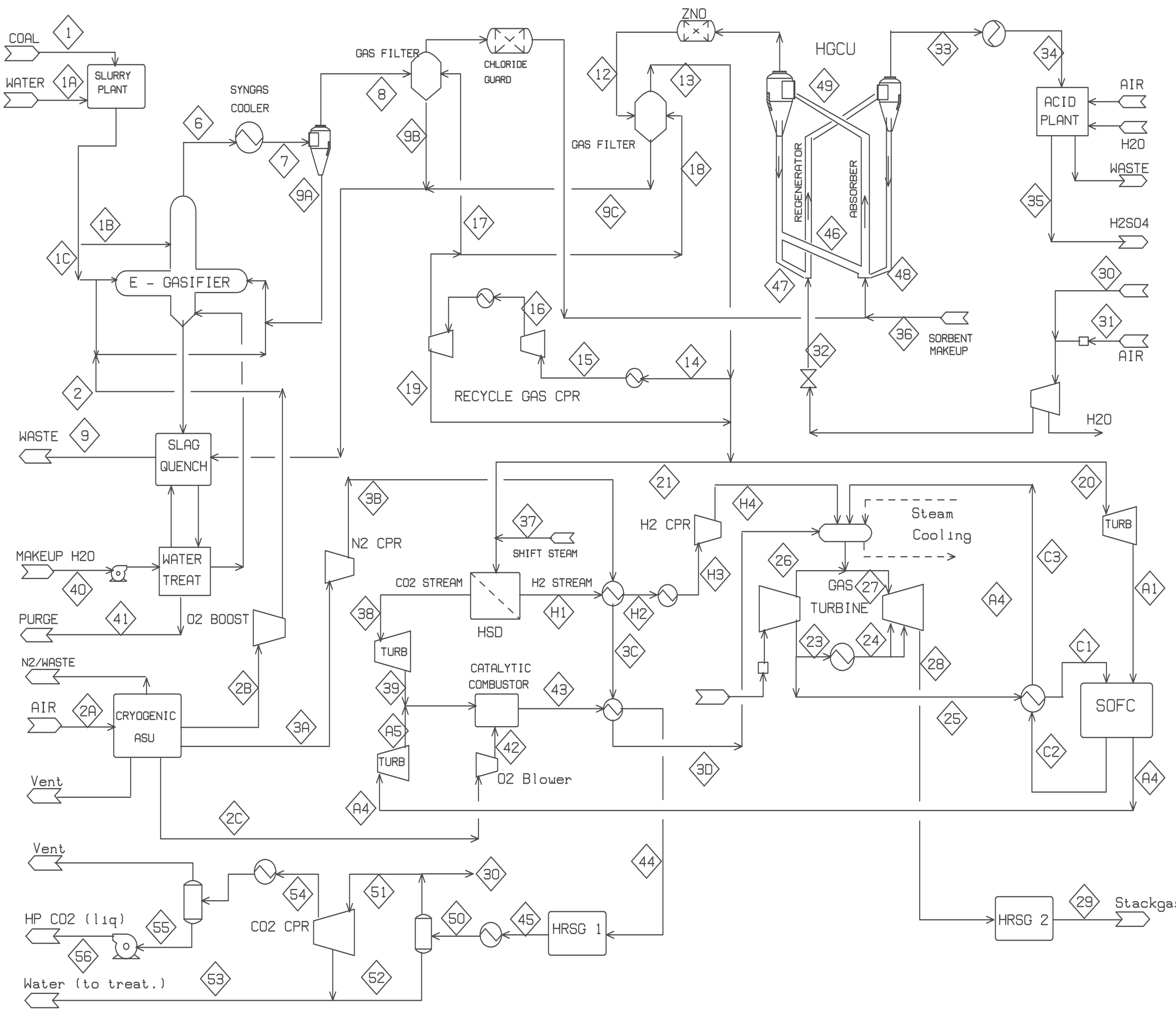


Figure 25. Case 2 . Hybrid GT/SOFC – Coal Syngas – CO_2 capture

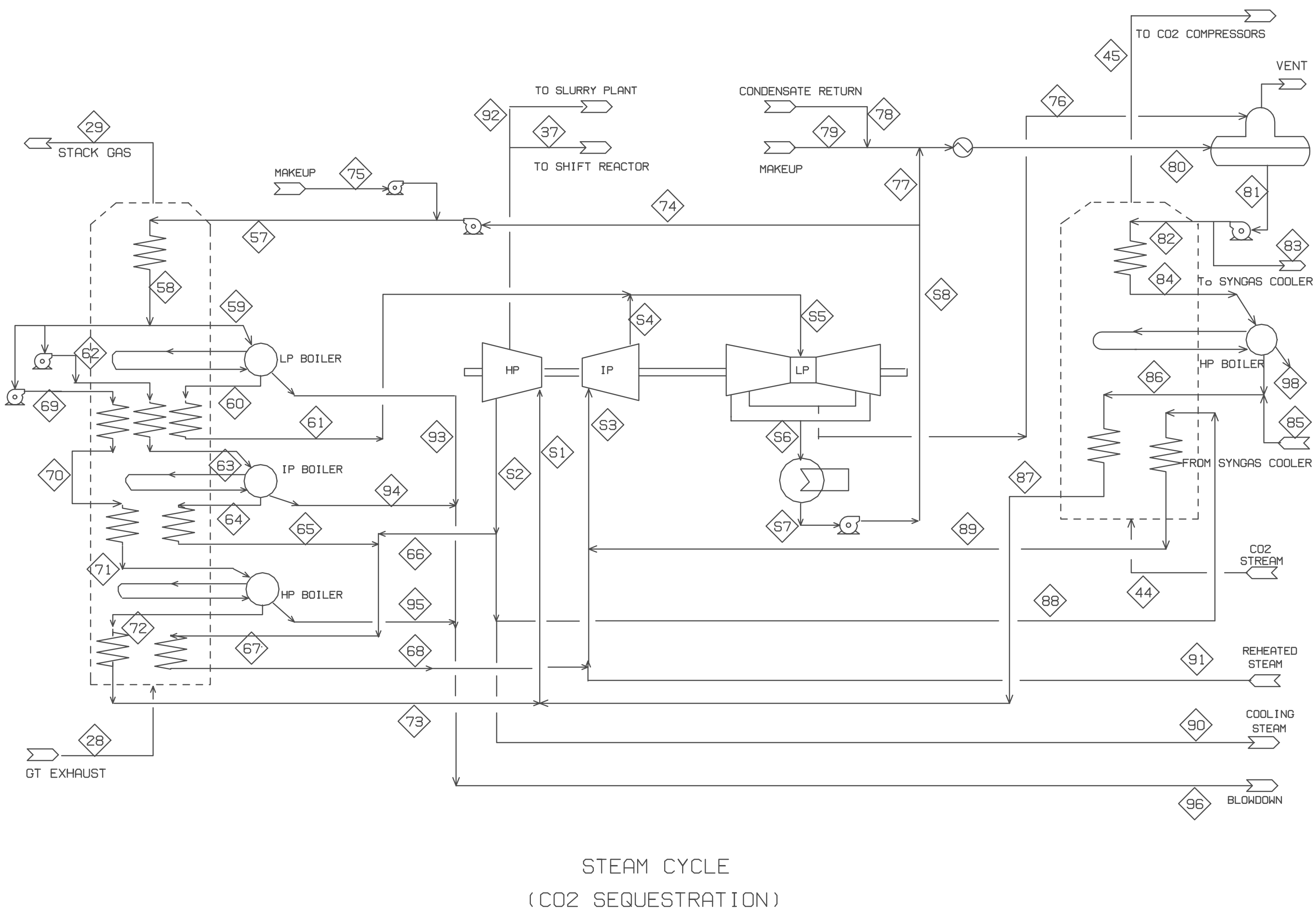


Figure 26. Case 2 . Hybrid GT/SOFC – Coal Syngas – CO_2 capture

II-4.2.3 Hybrid - Turbine/Fuel Cell Cycles – Coal Cases – Case 3 (No CO_2 Capture)

Case 3 was initially developed as part of a CRADA between NETL and Praxair [29]. This CRADA examined replacing the cryogenic ASU for oxygen production with a membrane process (OTM) in a number of power plant schemes. Case 3 is included in the present report to provide a hybrid that integrates the SOFC with both the ASU and the gas turbine. This takes advantage of the similarity in operating temperature between the OTM and SOFC. Additionally the case uses a CGCU (RECTISOL) to clean the fuel gas to low sulfur levels. In Figure 27, the process is shown. Details of the SOFC/OTM process are confidential and were provided to NETL as a "black box" as shown on the flow diagram. (The Aspen Plus® model developed used a combination of intrinsic reactor models (RGIBBS) and separation operations to obtain approximately the information furnished by Praxair.) Key features include:

- A commercially available process, RECTISOL, is used instead of the HGCU approach used in Case 1 and Case 2 to remove sulfur from the fuel stream.

- The ASU is based on an advanced process under development that is projected to have lower costs and lower energy requirements compared with cryogenic oxygen plants.

- The SOFC is integrated both with the gas turbine and the ASU (OTM). The combined air stream from the gas turbine and supplemental compressor and fuel from the gasification unit are sent to the SOFC/OTM section. The SOFC is assumed to produce power at 50% efficiency.

- CO_2 capture is not included. It is expected that modifications are possible that would result in a CO_2 rich stream. However, an efficiency penalty of 6-7% would be projected as in other cases.

- Developers of ASU processes expect performance and costs to improve over the assumptions used for the present case that yields a 57% (LHV) efficiency.

- The steam cycle integrates available heat into a three pressure level steam cycle similar to Case 1. Steam is provided for the CGCU and Slurry plant sections.

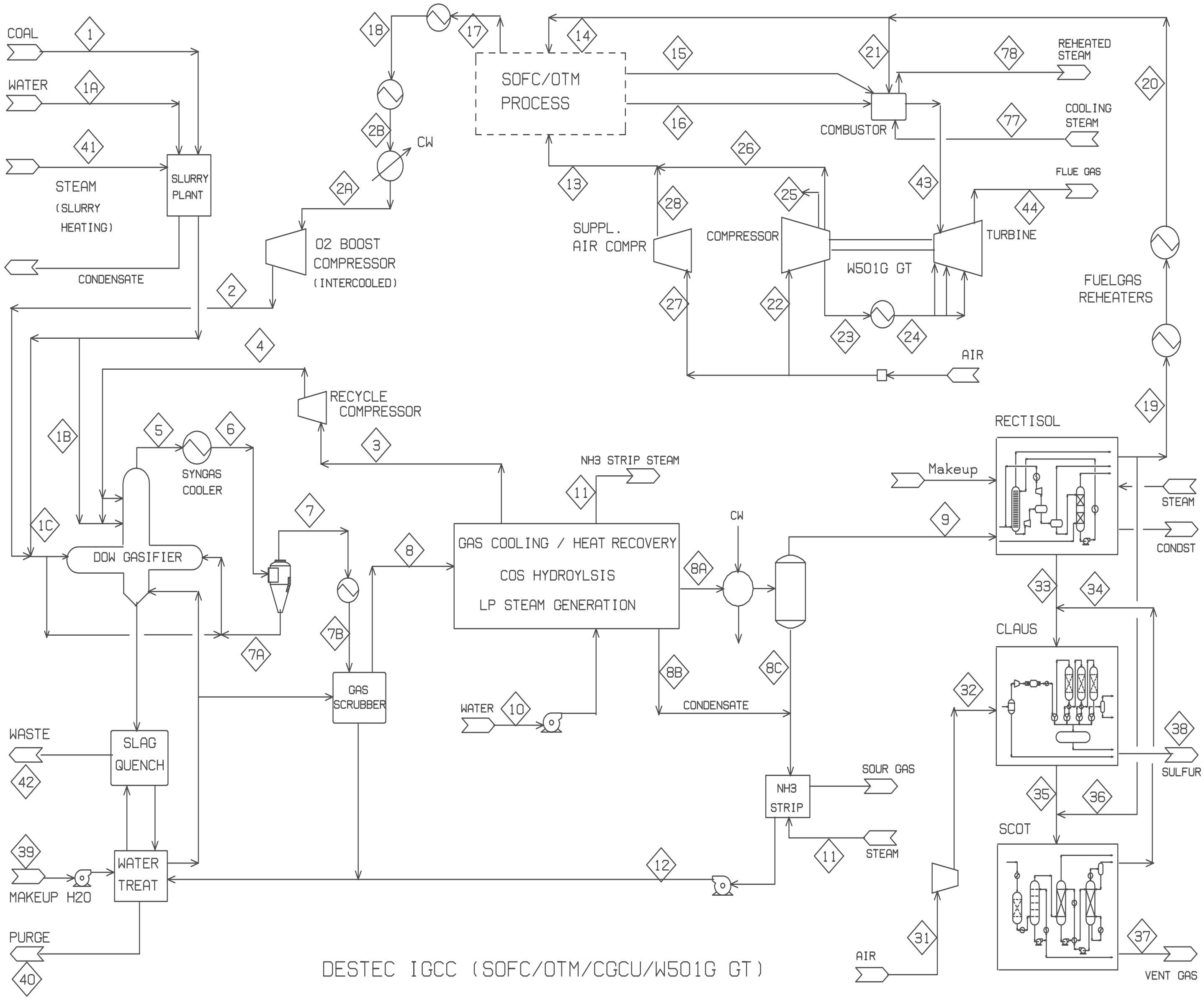


Figure 27. Case 3 . Hybrid GT/SOFC/OTM – Coal Syngas – No CO_2 Capture

II-4.3 Hybrid - Turbine/Fuel Cell Cycles – Summary

The Hybrid cases based on using a combination of a SOFC and turbines resulted in the highest efficiencies obtained for the systems included in this report. The systems considered as summarized in Table 11 have efficiencies that are approaching the goals of the Vision 21 program of 75% (LHV, natural gas) and 60% (HHV, coal). The coal cases considered in this report will have higher efficiencies as more of the fuel is sent directly to the fuel cell. The fuel split assumed was primarily made because of the high cost currently projected for fuel cells and the use of the “G” turbine. The natural gas case uses turbines with relatively low firing temperatures and performance will increase with different choices for the turbines. However, this optimistic feeling is made assuming that the fuel cells performance can be demonstrated for large modules and that the cost ($/KW) is drastically reduced.

II-5. HUMID AIR TURBINE (HAT) CYCLES

Humid Air Turbine (HAT) cycles have been proposed for a number of years as a means for reducing costs when compared to Combined Cycles (CC). A typical HAT cycle uses a high pressure ratio gas turbine (pressure ratio > 50) composed of a high pressure intercooled shaft and a low pressure power shaft . The high pressure air from the compressor is cooled and then humidified in an air saturator. The humidified air is heated in a heat recovery section that uses the turbine exhaust before entering the turbine combustor. Compared to a combined cycle , the argument is usually made that while the efficiency of the HAT cycle is typically lower by several percentage points that the advantage is in the cost being lower. This is based on the HAT cycle claiming that eliminating the HRSG/Steam Cycle reduces cost more than the added cost of a more expensive gas turbine and the addition of the air saturator and a number of heat exchangers.

Two HAT cycles were considered in the present study (natural gas case, and a syngas case) based on a turbine design provided to NETL by Pratt & Whitney Power Systems (PWPS) [31]. Comparisons to the reference cases for NGCC and a Destec/CGCU IGCC indicated approximately the same efficiencies and higher costs for the HAT cycles. PWPS would not provide a cost estimate for the high pressure ratio gas turbine since it’s currently in the research and development stage. This cost was estimated based on information from the EG&G Cost Estimating Notebook (version 1.11) and are included with the COE spreadsheets for these cases in Appendix B. (The COE results can be easily revised if information becomes available.) Since the two HAT cases developed demonstrated no advantage over reference cases, HAT cycles that include carbon dioxide capture were not considered. NETL is currently funding systems studies (no COE analysis) based on HAT cycles combined with SOFC [28], that demonstrate high efficiencies. However, the efficiency gain found in these studies is due to the use of fuel cells and partly due to optimistic efficiencies assumed for compressors and turbine expanders. HAT cycles in non-hybrid systems appear to have no hope of meeting Vision 21 goals. The results obtained for the two cases in the present study are listed in Table 13.

Table 13. HAT Cycle Summary

POWER SYSTEM	HUMID AIR TURBINE (HAT)	
Generation Cycle	HAT (PW GT) Natural Gas	HAT COAL (PW GT) Destec (E-Gas) CGCU
Net Pow er MWe	318.7	407.4
Net Plant Efficiency	57.6	44.9
% LHV		
Total Capital Requirement	873	1552
$ / KW		
Cost of Electricity	47	45.1
Constant $ / MW-hr		
NOx emissions	0.074	0.071
lb/MW-hr		
Sox emissions	---	0.353
lb/MW-hr		
CO2 Production		
lb/MW-hr		
a) Emitted to atmosphere	758	1576
b) Sequesterable		
Footprint (battery limits)	175	811
sq ft/MW		

II-5.1 Humid Air Turbine (HAT) Cycles – Natural Gas

Based on the information provided by PWPS, a natural gas HAT cycle was developed and is shown in Figure 28. The aeroderivative turbine consists of a dual shaft arrangement having an overall pressure ratio of 54.2. Other conditions include an inlet air flowrate of 643.3 lbs/sec and a turbine inlet temperature of 2750 ^{o}F. The HAT approach results in the elimination of the HRSG/Steam Cycle of the NGCC and adds several heat exchangers (water heating), an air saturator and a heat recovery section. The heat integration allows the high pressure air stream exiting the saturator to have a moisture content of 19.2%. This plant produces a net power of

318.7 MWe and has an efficiency of 57.6% (LHV). Appendix A contains the material and energy balances and the COE is included in Appendix B.

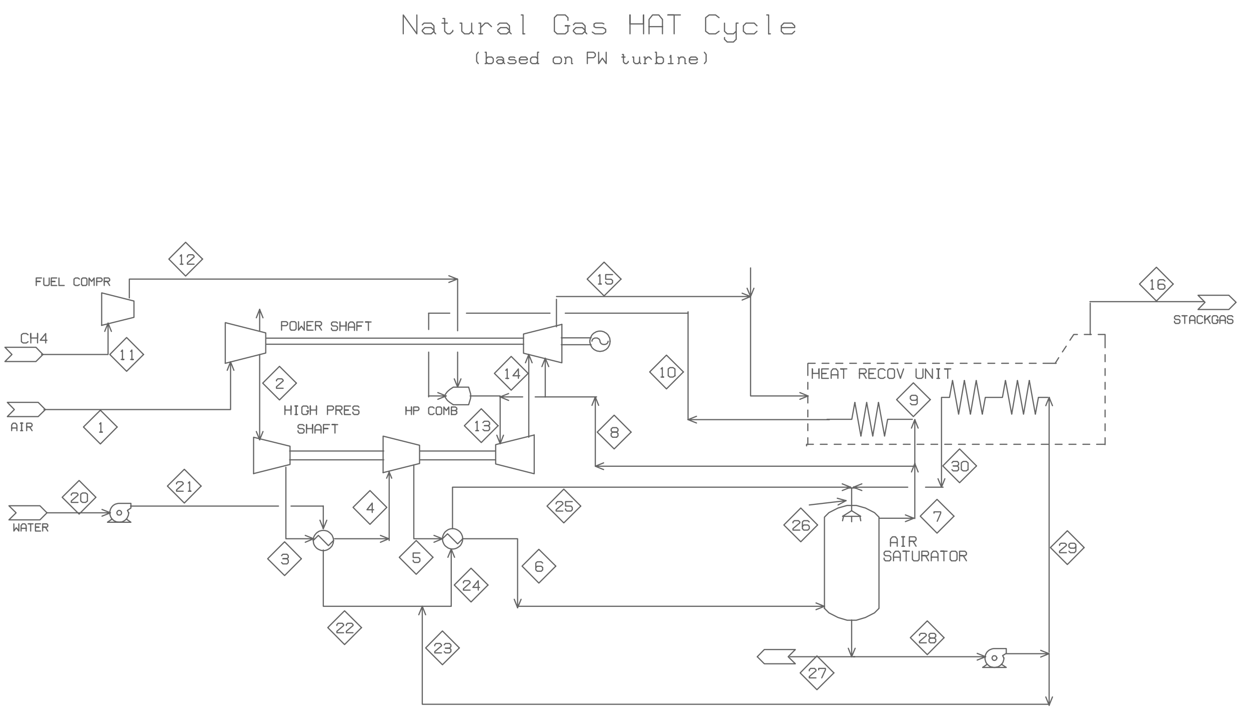


Figure 28. HAT Cycle – Natural Gas - PW Aeroderivative Turbine

II-5.2 Humid Air Turbine (HAT) Cycles – Coal Syngas

An Aspen Plus® simulation model was developed for an Integrated Gasification Humid Air Turbine (IGHAT) based on the following key sections:

- Destec (E-Gas) Gasifier - operates at exit conditions of 1900 ^{o}F and 412 psia. Condition and model incorporated from reference Destec/CGCU case.
- ASU – cryogenic oxygen plant (low pressure).
- High Temperature Syngas Cooling - used to both reheat the clean syngas and to heat high pressure water sent to the air saturator.
- Low Temperature Syngas Cooling – includes COS Hydrolysis and heat recovery. Heat recovery used to generate low pressure steam used for the CGCU section stripper and slurry heating. Condenses most of the water from syngas.
- CGCU – used MDEA/CLAUS/SCOT system for sulfur recovery.
- Syngas Compressor / Reheater – compresses and reheats the clean syngas from the MDEA section for use in the gas turbine combustor.
- PW Aeroderivative Turbine – uses the turbine model representation developed for the natural gas HAT case. (Pressure Ratio = 54.2, TIT = 2750 ^{o}F)
- Air Saturator – used to humidify the high pressure air from the gas turbine.
- Heat Recovery Unit (HRU) – uses the turbine exhaust to heat the air from the saturator and to heat a portion of the water used in the saturator.

Figure 29 shows a flow diagram for the process which resulted in a net power generation of 407.3 MWe and an overall efficiency of 44.9% (LHV). This is slightly lower when compared to the 46.7% obtained for the reference Destec/CGCU IGCC process. Material and Energy balance summaries are in Appendix A and the COE spreadsheet results are in Appendix B.

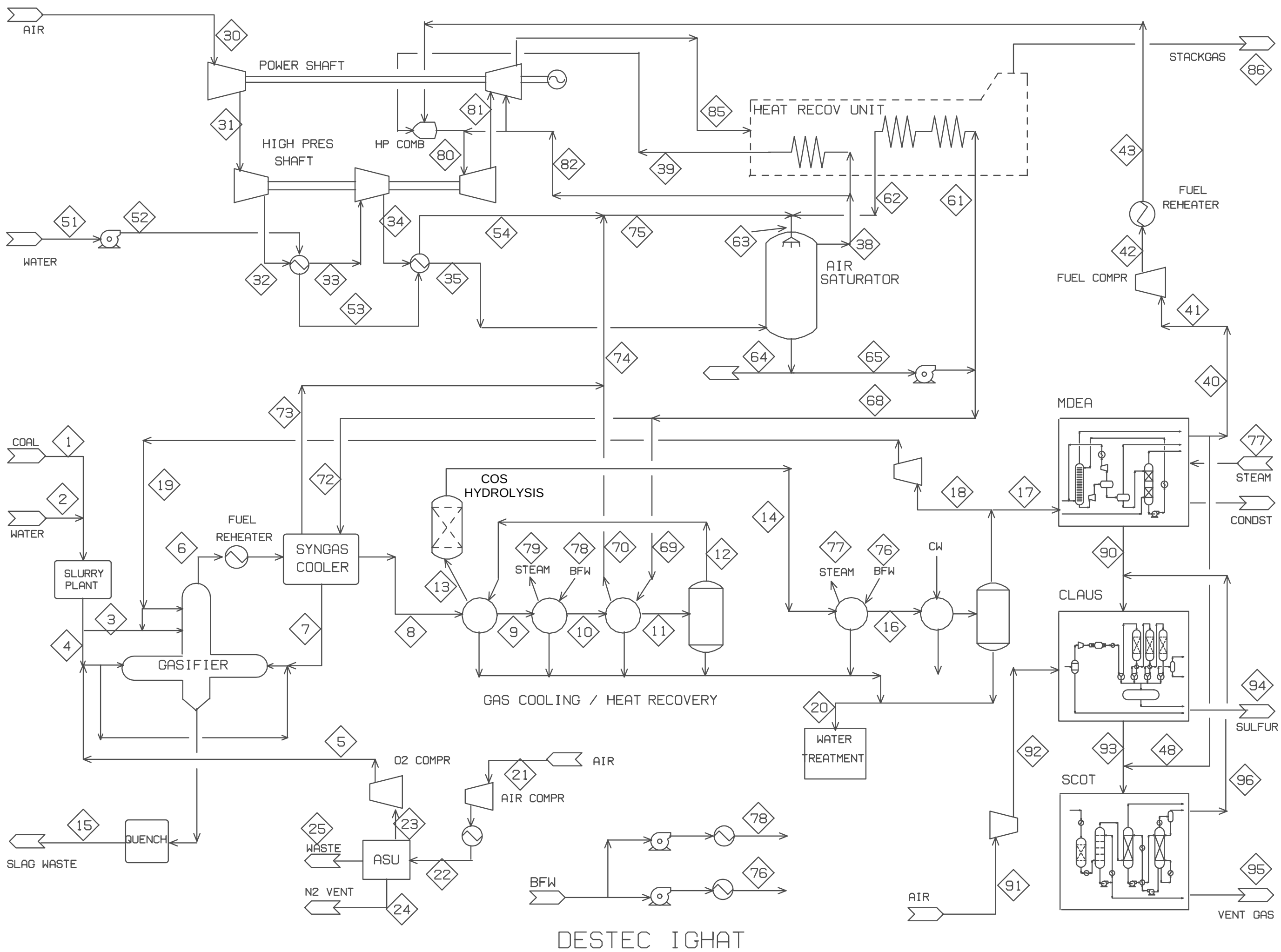


Figure 29. IGHAT – Destec/ CGCU

II-5.3 Humid Air Turbine (HAT) Cycles - Summary

HAT cycles produced efficiencies that were only comparable to corresponding reference combined cycles (NGCC, IGCC). HAT cycles without the addition of a fuel cell and the resulting conversion to a hybrid cycle will not be able to achieve anywhere near Vision 21 objectives. In Table 14 following, a summary is provided of key conditions used and a comparison with simulation results provided by PWPS [31] for a modified HAT cycle based on a TEXACO gasifier. This case uses a small steam cycle and results in a lower moisture content for the humidified air when compared to the Destec HAT cycle. The efficiency is somewhat higher but still significantly below Vision 21 objectives. Systems studies that include hybrid HAT cycles are currently being funded by NETL [28].

Table 14. Comparison with P&W hybrid system and NETL IGHAT Cycle

	P&W IGHAT	NETL IGHAT	NETL NGHAT
Fuel	Syngas (TEXACO Gasifier)	Syngas (DESTEC Gasifier)	Natural Gas (CH4)
Gas Turbine:			
- Pressure Ratio :	54.2	54.2	54.2
- Inlet Air (lbs/sec):	643.3	643.3	643.3
- TIT (^{o}F) :	2750	2750	2750
- weight % Moisture : (air to Combustor)	17	28.1	19.2
Results			
Power (MWe)			
- Gas Turbine	359.9	457.6	326.5
- Steam Turbine	69.6		
- Expander	5		
- Total Gross	434.5	457.6	326.5
- Misc & Aux	51.4	50.2	7.8
- Net Power	383.1	407.4	318.7
Efficiency %			
- HHV	46	43.3	51.9
- LHV	47.7	44.9	57.6

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Appendix A

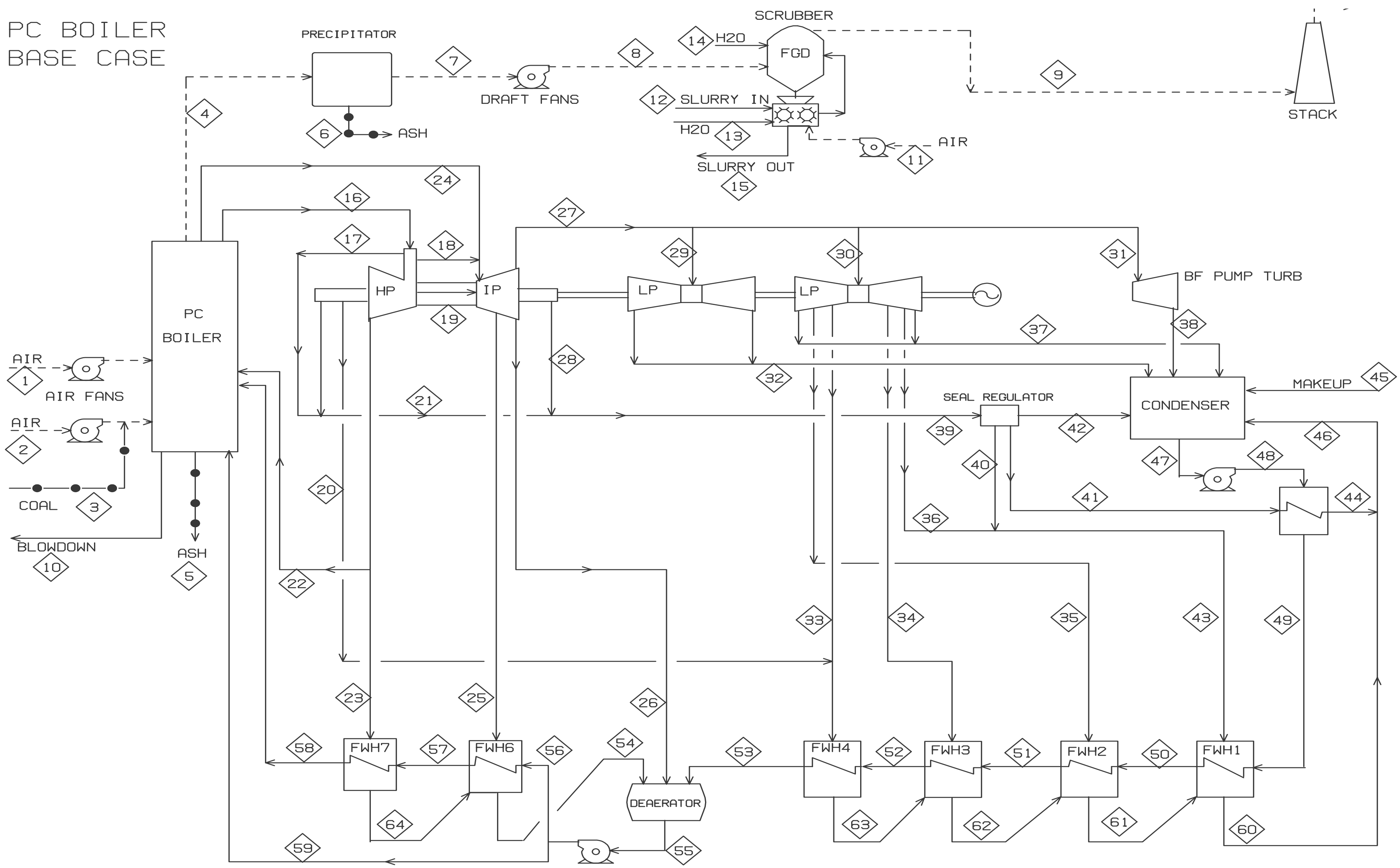
Process Flow Diagrams
Material & Energy Balances

(continued)

Process Flow Diagrams
Material & Energy Balances

Pulverized Coal (PC)

PC Steam Cycle – No CO_2 Capture


PC BOILER
BASE CASE
PRECIPITATOR
DRAFT FANS
ASH
SCRUBBER
FGD
H2O
SLURRY IN
SLURRY OUT
AIR
STACK
PC
BOILER
AIR
AIR FANS
COAL
BLOWDOWN
HP
IP
LP
BF PUMP TURB
SEAL REGULATOR
CONDENSER
MAKEUP
FWH7
FWH6
DEAERATOR
FWH4
FWH3
FWH2
FWH1

Streams Summary

PFD ID	1	2	3	4	5	6	7
ASPEN STREAM ID	AIRFD	AIRPR	COALFEED	TOESP	ASH5	ASH6	FLUEGAS
Description	Main Air	Primary Air	Coalfeed	to ESP	Ash Boiler	Ash ESP	Fluegas
Temperature F	60	60	59	289.1	289.1	289.1	289.1
Pressure psi	14.7	14.7	14.7	14.4	14.4	14.4	14.4
Mass Flow lb/hr	2675327	821832	309464	3800348	6272	25088	3775260
Mole Flow lbmol/hr	92712	28480					127371
Enthalpy MMBtu/hr	-111.1	-34.1	-1138.9	-3696.6	-14.6	-58.5	-3638.1
Mole Frac							
O2	0.20747	0.20747		0.04557			0.04557
N2	0.77316	0.77316		0.73674			0.73674
AR	0.00921	0.00921		0.00876			0.00876
CO2	0.00030	0.00030		0.12835			0.12835
H2O	0.00986	0.00986		0.07858			0.07858
SO2				0.00190			0.00190
CL2				0.00010			0.00010
TOTAL	1.00000	1.00000		1.00000			1.00000

FLOW DIA. ID	8	9	10	11	12	13	14
ASPEN STREAM ID	20	TOSTACK	BDWN	OXIDANT	LMSTONE	SH2O	H2OMX
Description	to FGD	to Stack	H2O blowdn	Air to FGD	Lmstone	H2O - FGD	H2O -FGD
Temperature F	299.9	129	674.1	60	60	68	68
Pressure psi	15.1	14.8	2600	14.7	14.7	14.7	15
Mass Flow lb/hr	3775260	3973687	13125	61971	96893	229745	107124
Mole Flow lbmol/hr	127371	137427	729	2148	4040	12753	5946
Enthalpy MMBtu/hr	-3627.8	-4630.9	-80.3	-2.6	-623.4	-1578.8	-736.2
Mole Frac							
O2	0.04557	0.04467		0.20747			
N2	0.73674	0.69491		0.77316			
AR	0.00876	0.00826		0.00921			
CO2	0.12835	0.12058		0.00030			
H2O	0.07858	0.13134	1.00000	0.00986	1.00000	1.00000	1.00000
SO2	0.00190	0.00014		0.00000			
CL2	0.00010	0.00009		0.00000			
TOTAL	1.00000	1.00000	1.00000	1.00000			

FLOW DIAGRAM ID	15	16	17	18	19	20	21
ASPEN STREAM ID	SLURRY	H1	H2	H3	H4	H5	H7
Description	Slurry exit	Steam-HP	bleed	bld to ip	bld to ip	to FWH4	to seal reg
Temperature F	129.1	1000	1000	1000	801.6	631.4	655.4
Pressure psi	14.8	2415	2415	2415	1207.5	603.6	603.6
Mass Flow lb/hr	297308	2734080	1083	3788	32207	5521	10989
Mole Flow lbmol/hr	14719	151763	60	210	1788	306	610
Enthalpy MMBtu/hr	-1949.1	-14780.2	-5.9	-20.5	-176.7	-30.7	-60.9
Mole Frac							
H2O	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
TOTAL	1.00000		1.00000	1.00000			

FLOW DIAGRAM ID	22	23	24	25	26	27	28
ASPEN STREAM ID	H8	H9	H8A	I2	I3	I4	I5
Description	stm->reheat	to FWH7	Reheat->IP	to FWH6	to Deaerator	to LP Turb	to seal reg
Temperature F	631.4	631.4	1000	811.8	695.1	695.1	695.1
Pressure psi	603.6	603.6	545.4	278.9	174.9	174.9	174.9
Mass Flow lb/hr	2425661	255913	2425661	81934	160845	2215094	3784
Mole Flow lbmol/hr	134643	14205	134643	4548	8928	122955	210
Enthalpy MMBtu/hr	-13477.7	-1421.9	-12970.8	-445.6	-883.6	-12168.4	-20.8
Mole Frac							
H2O	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
TOTAL							

Stream Summary (continued)

FLOW DIAGRAM ID	29	30	31	32	33	34	35
ASPEN STREAM ID	L1	L2	L3	L4	L5	L6	L7
Description	to LP #1	to LP #2	to LP #3	from LP #1	to FWH4	to FWH3	to FWH2
Temperature F	695.1	695.1	695.1	101.7	479.5	293.2	205.1
Pressure psi	174.9	174.9	174.9	1	66.5	24.2	12.8
Mass Flow lb/hr	866582	1248002	100510	866582	125975	68312	64645
Mole Flow lbmol/hr	48102	69274	5579	48102	6993	3792	3588
Enthalpy MMBtu/hr	-4760.5	-6855.8	-552.1	-5070.8	-704.7	-388	-370
Mole Frac							
H2O	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
TOTAL	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000

FLOW DIAGRAM ID	36	37	38	39	40	41	42
ASPEN STREAM ID	L8	L9	L10	S1	S2	S3	S4
Description	to FWH1	From LP #2	from LP #3	to seal reg	to FWH1	to cd reheat	to Deaer
Temperature F	172.2	110.7	113.3	625.2	625.2	625.2	625.2
Pressure psi	6.3	1.3	1.4	174.9	174.9	174.9	174.9
Mass Flow lb/hr	118188	835339	100510	14773	9545	2815	2413
Mole Flow lbmol/hr	6560	46368	5579	820	530	156	134
Enthalpy MMBtu/hr	-677.4	-4862.6	-586.5	-81.7	-52.8	-15.6	-13.3
Mole Frac							
H2O	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
TOTAL	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000

FLOW DIAGRAM ID	43	44	45	46	47	48	49
ASPEN STREAM ID	S5	S6	MK1	C0	CD0	CDA	CD1
Description	to FWH1	to Deaer	makeup	to Deaer	from Cond	pump cdn	cdn-->FWH1
Temperature F	204.7	113.3	60	106.3	96.4	96.7	98.3
Pressure psi	6.3	1.4	14.7	1.4	0.9	330	321
Mass Flow lb/hr	127733	2815	13125	395001	2248513	2248513	2248513
Mole Flow lbmol/hr	7090	156	729	21926	124810	124810	124810
Enthalpy MMBtu/hr	-730.1	-19.1	-89.7	-2682.8	-15293.5	-15290.9	-15287.3
Mole Frac							
H2O	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
TOTAL	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000

FLOW DIAGRAM ID	50	51	52	53	54	55	56
ASPEN STREAM ID	CD2	CD3	CD4	CD5	C76	C5	P1
Description	cdn-->FWH2	cdn-->FWH3	cdn-->FWH4	to Deaer	to Deaer	from Deaer	to FWH6
Temperature F	167.8	199.4	232	293.5	405.7	365.9	372.3
Pressure psi	300	250	210	175	263.8	164.8	2903.3
Mass Flow lb/hr	2248513	2248513	2248513	2248513	337847	2747205	2652976
Mole Flow lbmol/hr	124810	124810	124810	124810	18753	152491	147261
Enthalpy MMBtu/hr	-15131.7	-15060.8	-14987.3	-14847.2	-2190.4	-17933.2	-17289.7
Mole Frac							
H2O	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
TOTAL	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000

FLOW DIAGRAM ID	57	58	59	60	61	62	63	64
ASPEN STREAM ID	P3	P4	P2	C1	C2	C3	C4	C7
Description	to FWH7	to econ	to pc	from FWH1	from FWH2	from FWH3	from FWH4	from FWH7
Temperature F	404.3	485.5	372.3	106.2	175.4	206.7	239.1	415.5
Pressure psi	2620	2758	2903.3	6	11.9	22.4	62.4	588.5
Mass Flow lb/hr	2652976	2652976	94229	392186	264453	199808	131495	255913
Mole Flow lbmol/hr	147261	147261	5230	21769	14679	11091	7299	14205
Enthalpy MMBtu/hr	-17201.6	-16966.7	-614.1	-2663.7	-1777.8	-1337	-875.6	-1656.8
Mole Frac								
H2O	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
TOTAL	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000

POWER SUMMARY PC Steam Cycle - No CO2 Capture

TURBINE SECTION	POWER KW
HP TURBINE	-119608.27
IP TURBINE	-102672.41
LP TURBINE #1	-90957.98
LP TURBINE #2	-113113.83
TOTAL TURBINE	**-426352.49**
GENERATOR LOSS	6395.29
NET STEAM TURBINE	**-419957.19**

	POWER KW	
LP Turb #3	-10068.36	(lp turb #3 supplies power for
HP Pump	8632.28	the hp feedwater pump)
extra	-1436.08	

***NOTE - ASPEN sign convention
"-" power produced
"+" power required

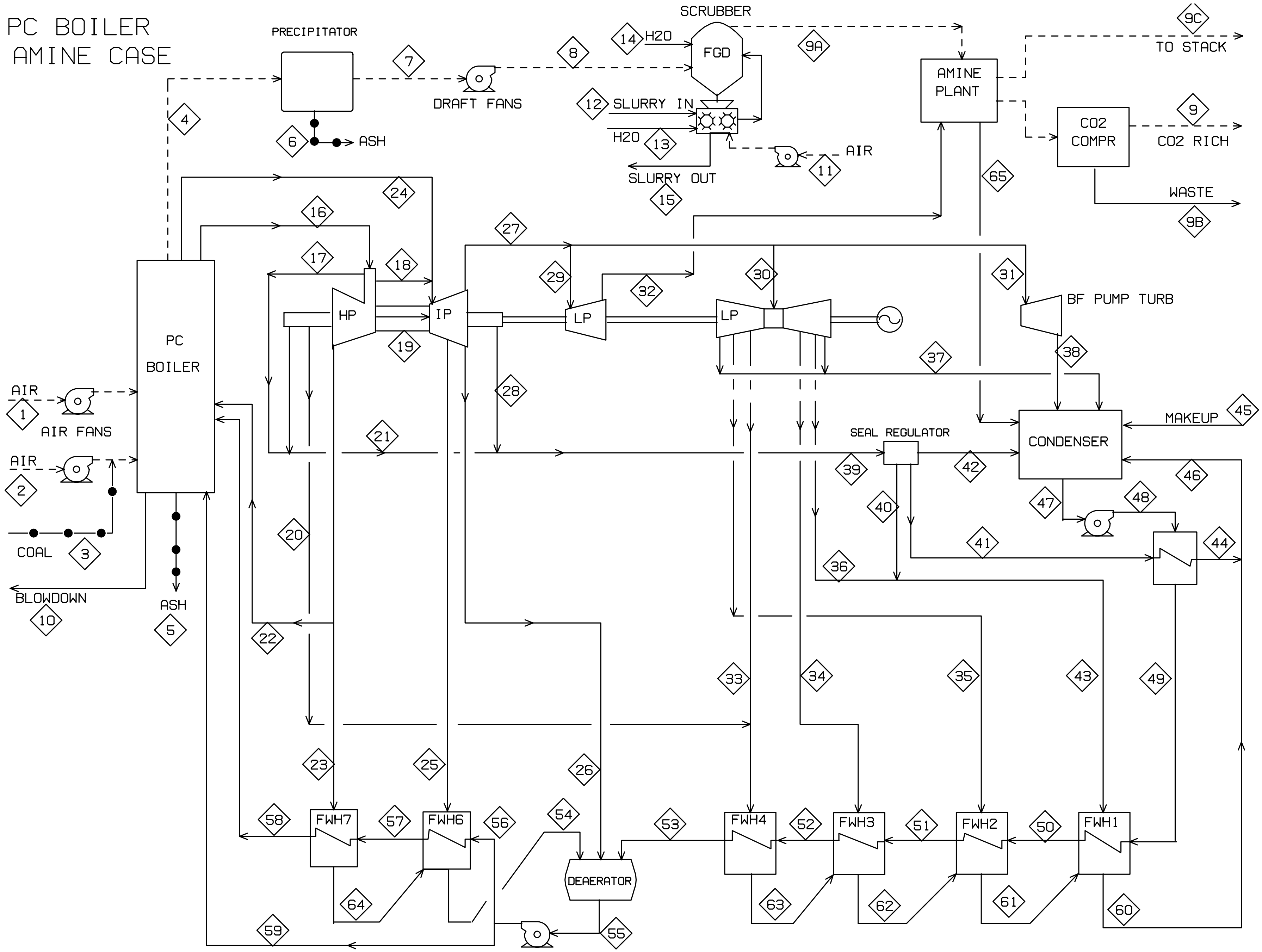
DRAFT FANS	POWER KW
- Primary Air	915.19
- Forced	871.17
- Induced	3057.95
TOTAL FANS	**4844.31**

MISC WORK	**17564.86**
CONDENSER PUMP	**755.99**

NET POWER (MWe)	**-396.79**
COALFEED (LBS/HR)	**309464.00**
EFF % (HHV)	**37.51**

Pulverized Coal (PC)

PC Steam Cycle - Amine CO_2 Capture



PC BOILER
AMINE CASE
PRECIPITATOR
ASH
DRAFT FANS
SCRUBBER
H2O
FGD
SLURRY IN
H2O
SLURRY OUT
AIR
AMINE PLANT
TO STACK
CO2 COMPR
CO2 RICH
WASTE
PC BOILER
AIR
AIR FANS
AIR
COAL
BLOWDOWN
ASH
HP
IP
LP
LP
BF PUMP TURB
SEAL REGULATOR
CONDENSER
MAKEUP
FWH7
FWH6
DEAERATOR
FWH4
FWH3
FWH2
FWH1
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9A
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Amine Case - Stream Summary

FLOW DIA. ID	1	2	3	4	5	6	7
ASPEN STREAM ID	AIRFD	AIRPR	COALFEED	TOESP	ASH5	ASH6	FLUEGAS
Description	Main Air	Primary Air	Coalfeed	to ESP	Ash Boiler	Ash ESP	Fluegas
Temperature F	60	60	59	289.1	289.1	289.1	289.1
Pressure psi	14.7	14.7	14.7	14.4	14.4	14.4	14.4
Mass Flow lb/hr	2675327	821832	309464	3800348	6272	25088	3775260
Mole Flow lbmol/hr	92712	28480					127371
Enthalpy MMBtu/hr	-111.1	-34.1	-1138.9	-3696.6	-14.6	-58.5	-3638.1
Mole Frac							
O2	0.20747	0.20747		0.04557			0.04557
N2	0.77316	0.77316		0.73674			0.73674
AR	0.00921	0.00921		0.00876			0.00876
CO2	0.00030	0.00030		0.12835			0.12835
H2O	0.00986	0.00986		0.07858			0.07858
SO2	0.00000	0.00000		0.00190			0.00190
CL2	0.00000	0.00000		0.00010			0.00010
TOTAL	1.00000	1.00000		1.00000			1.00000

FLOW DIA. ID	8	9A	9B	9C	9	11	12
ASPEN STREAM ID	20	TOAMINE	LIQW	STACKGAS	CO2HP	OXIDANT	LMSTONE
Description	to FGD	to MEA	liquid waste	to stack	HP CO2	Air to FGD	Lmstone
Temperature F	299.9	129	95.7	101	228	60	60
Pressure psi	15.1	14.8	14.7	14.7	1500	14.7	14.7
Mass Flow lb/hr	3775260	3973687	234034	3058207	692907	61971	96893
Mole Flow lbmol/hr	127371	137427	12979	110132	15772	2148	4040
Enthalpy MMBtu/hr	-3627.8	-4630.9	-1603.4	-1040.2	-2665.1	-2.6	-623.4
Mole Frac							
O2	0.04557	0.04467	0.00000	0.05575	0.00006	0.20747	0.00000
N2	0.73674	0.69491	0.00000	0.86727	0.00045	0.77316	0.00000
AR	0.00876	0.00826	0.00000	0.01031	0.00000	0.00921	0.00000
CO2	0.12835	0.12058	0.00044	0.00741	0.99677	0.00030	0.00000
H2O	0.07858	0.13134	0.99951	0.05910	0.00272	0.00986	1.00000
SO2	0.00190	0.00014	0.00000	0.00000	0.00000	0.00000	0.00000
CL2	0.00010	0.00009	0.00000	0.00000	0.00000	0.00000	0.00000
MEA	0.00000	0.00000	0.00005	0.00016	0.00000	0.00000	0.00000
TOTAL	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000

FLOW DIAGRAM ID	10	13	14	15	16	17	18
ASPEN STREAM ID	BDWN	SH2O	H2OMX	SLURRY	H1	H2	H3
Description	H2O - bldn	H2O - FGD	H2O -FGD	Slurry exit	Steam-HP	bleed	bld to ip
Temperature F	674.1	68	68	129.1	1000	1000	1000
Pressure psi	2600	14.7	15	14.8	2415	2415	2415
Mass Flow lb/hr	13125	229745	107124	297308	2734080	1083	3788
Mole Flow lbmol/hr	729	12753	5946	14719	151763	60	210
Enthalpy MMBtu/hr	-80.3	-1578.8	-736.2	-1949.1	-14780.2	-5.9	-20.5
Mole Frac							
H2O	1.00000	1	1		1	1	1
TOTAL	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000

FLOW DIAGRAM ID	19	20	21	22	23	24	25
ASPEN STREAM ID	H4	H5	H7	H8	H9	H8A	I2
Description	bld to ip	to FWH4	to seal reg	stm->reheat	to FWH7	Reheat->IP	to FWH6
Temperature F	801.6	631.4	655.4	631.4	631.4	1000	811.8
Pressure psi	1207.5	603.6	603.6	603.6	603.6	545.4	278.9
Mass Flow lb/hr	32207	5521	10989	2425661	255913	2425661	81934
Mole Flow lbmol/hr	-176.7	-30.7	-60.9	-13477.7	-1421.9	-12970.8	-445.6
Enthalpy MMBtu/hr	1788	306	610	134643	14205	134643	4548
Mole Frac							
H2O	1	1	1	1	1	1	1
TOTAL	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000

Amine Case - Stream Summary

FLOW DIAGRAM ID	26	27	28	29	30	31	32
ASPEN STREAM ID	I3	I4	I5	L1	L2	L3	STMAMN
Description	to Deaerator	to LP Turb	to seal reg	to LP #1	to LP #2	to LP #3	to MEA
Temperature F	695.1	695.1	695.1	695.1	695.1	695.1	372.4
Pressure psi	174.9	174.9	174.9	174.9	174.9	174.9	35
Mass Flow lb/hr	160845	2215094	3784	1276467	838117	100510	1276467
Mole Flow lbmol/hr	8928	122955	210	70854	46522	5579	70854
Enthalpy MMBtu/hr	-883.6	-12168.4	-20.8	-7012.1	-4604.1	-552.1	-7203
Mole Frac							
H2O	1	1	1	1	1	1	1
TOTAL	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000

FLOW DIAGRAM ID	33	34	35	36	37	38	39
ASPEN STREAM ID	L5	L6	L7	L8	L9	L10	S1
Description	to FWH4	to FWH3	to FWH2	to FWH1	from LP #2	from LP #3	to seal reg
Temperature F	479.5	293.2	205.1	172.2	110.7	113.3	625.2
Pressure psi	66.5	24.2	12.8	6.3	1.3	1.4	174.9
Mass Flow lb/hr	125975	24300	27946	40100	596082	100510	14773
Mole Flow lbmol/hr	6993	1349	1551	2226	33087	5579	820
Enthalpy MMBtu/hr	-704.7	-138	-159.9	-229.8	-3469.9	-586.5	-81.7
Mole Frac							
H2O	1	1	1	1	1	1	1
TOTAL	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000

FLOW DIAGRAM ID	40	41	42	43	44	45	46
ASPEN STREAM ID	S2	S3	S4	S5	S6	MK1	C0
Description	to FWH1	to cd reheat	to Deaer	to FWH1	to Deaer	makeup	to Deaer
Temperature F	625.2	625.2	625.2	255.9	113.3	60	106.3
Pressure psi	174.9	174.9	174.9	6.3	1.4	14.7	1.4
Mass Flow lb/hr	9545	1408	3820	49645	1408	13125	234795
Mole Flow lbmol/hr	530	78	212	2756	78	729	13033
Enthalpy MMBtu/hr	-52.8	-7.8	-21.1	-282.6	-9.5	-89.7	-1594.7
Mole Frac							
H2O	1	1	1	1	1	1	1
TOTAL	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000

FLOW DIAGRAM ID	47	48	49	50	51	52	53
ASPEN STREAM ID	CD0	CDA	CD1	CD2	CD3	CD4	CD5
Description	from Cond	Pump cdn	cdn-->FWH1	cdn-->FWH2	cdn-->FWH3	cdn-->FWH4	to Deaer
Temperature F	96.4	96.7	98.6	168.1	202	231.6	293.5
Pressure psi	0.9	330	321	300	250	210	175
Mass Flow lb/hr	972046	972046	972046	972046	972046	972046	2248513
Mole Flow lbmol/hr	53956	53956	53956	53956	53956	53956	124810
Enthalpy MMBtu/hr	-6611.5	-6610.3	-6608.5	-6541.2	-6508.4	-6479.5	-14847.2
Mole Frac							
H2O	1	1	1	1	1	1	1
TOTAL	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000

FLOW DIAGRAM ID	54	55	56	57	58	59	60
ASPEN STREAM ID	C76	C5	P1	P3	P4	P2	C1
Description	to Deaer	from Deaer	to FWH6	to FWH7	to econ	to pc	from FWH1
Temperature F	405.7	365.9	372.3	404.3	485.5	372.3	106.2
Pressure psi	263.8	164.8	2903.3	2620	2758	2903.3	6
Mass Flow lb/hr	337847	2747205	2652976	2652976	2652976	94229	233387
Mole Flow lbmol/hr	18753	152491	147261	147261	147261	5230	12955
Enthalpy MMBtu/hr	-2190.4	-17933.2	-17289.7	-17201.6	-16966.7	-614.1	-1585.1
Mole Frac							
H2O	1	1	1	1	1	1	1
TOTAL	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000

Amine Case - Stream Summary

FLOW DIAGRAM ID	61	62	63	64	65		
ASPEN STREAM ID	C2	C3	C4	C7	11		
Description	from FWH2	from FWH3	from FWH4	from FWH7	from MEA		
Temperature F	175.4	206.7	239.1	415.5	232.3		
Pressure psi	11.9	22.4	62.4	588.5	215		
Mass Flow lb/hr	183742	155796	131496	255913	1276467		
Mole Flow lbmol/hr	10199	8648	7299	14205	70854		
Enthalpy MMBtu/hr	-1235.2	-1042.5	-875.6	-1656.8	-8507.8		
Mole Frac							
H_2O	1	1	1	1	1		
TOTAL	1.00000	1.00000	1.00000	1.00000	1.00000		

POWER SUMMARY - BASE CASE modified for providing steam to amine system reboiler
(Basis - CO_2 in exit gas = 692806 lbs/hr - 95% of CO_2 generated,
reboiler duty in amine system = 4.08 MMBTU/Metric Ton CO_2,
Steam provided from steam cycle at 35 psia and 372 F, Condensate return at 215 psia and 232 F,
Steam flowrate = 1276467 lbs/hr)

TURBINE SECTION	**POWER KW**	
HP TURBINE	-119608.27	
IP TURBINE	-102672.41	
LP TURBINE #1	-55936.54	****
LP TURBINE #2	-75546.58	****
TOTAL TURBINE	**-353763.80**	
GENERATOR LOSS	-5306.457	
NET STEAM TURBINE	-348457.34	

	POWER KW	
LP Turb #3	-10068.36	(lp turb #3 supplies power for
HP Pump	8632.28	the hp feedwater pump)
extra	-1436.08	

***NOTE - ASPEN sign convention
"-" power produced
"+" power required

DRAFT FANS	**POWER KW**
- Primary Air	915.19
- Forced	871.17
- Induced	3057.95
TOTAL FANS	**4844.31**

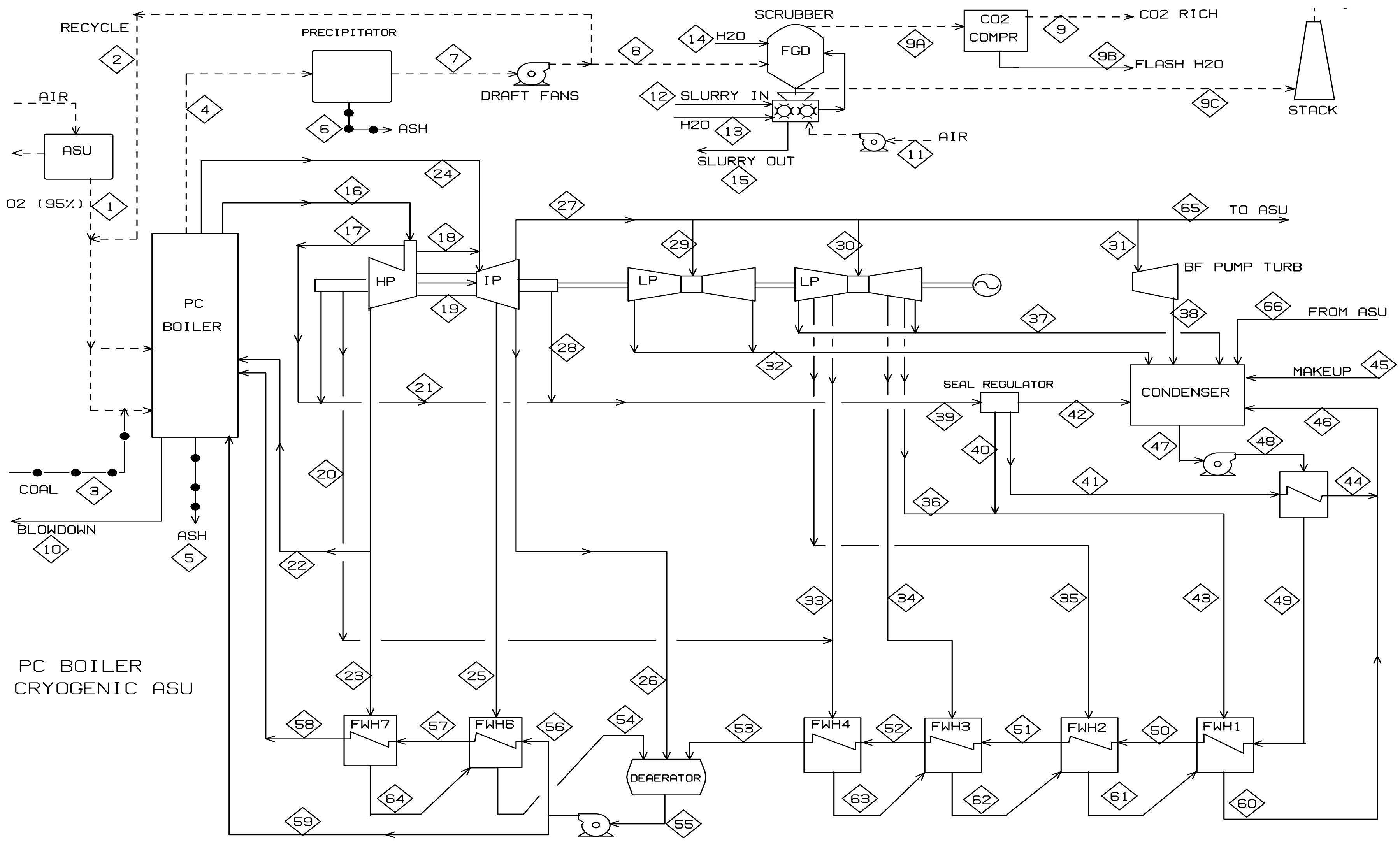
**** POWER REDUCED FROM BASE CASE DUE TO STEAM EXTRACTION FOR AMINE SYSTEM REBOILER,
LP Turbine section #2 was modified by reducing bleeds, assumes returning steam sent to the reboiler as condensate at 215 psia and 232 F

MISC WORK	**17564.86**	
CONDENSER PUMP	**343.09**	(REDUCED SINCE CONDSEROR FLOW IS REDUCED
COND. RETURN- AMINE	**266.47**	(PUMPS REBOILER CONDENSATE FROM 25 PSIA TO 215 PSIA)
Amine plant	**12567.90**	(calculated as 40 kWh/metric ton co2 * 692806/2205 metric ton co2)
CO2 COMPRESSOR	**29791.38**	717334.895 = compr inlet lb/hr
		709099.756 = compr outlet lb/hr (692806 lb/hr CO2)

NET POWER (MWe)	**-283.08**
COALFEED (LBS/HR)	**309464.00**
EFF % (HHV)	**26.76**

Pulverized Coal (PC)

PC Steam Cycle - O_2 Boiler / CO_2 Capture


RECYCLE
PRECIPITATOR
SCRUBBER
CO2 COMPR
CO2 RICH
FLASH H2O
STACK
DRAFT FANS
H2O
FGD
SLURRY IN
SLURRY OUT
AIR
ASU
O2 (95%)
ASH
PC BOILER
HP
IP
LP
LP
TO ASU
BF PUMP TURB
FROM ASU
MAKEUP
SEAL REGULATOR
CONDENSER
COAL
BLOWDOWN
FWH7
FWH6
DEAERATOR
FWH4
FWH3
FWH2
FWH1
PC BOILER
CRYOGENIC ASU

PC Steam Cycle – O2 Boiler/CO2 Capture - Stream Summary

FLOW DIA. ID	1	2	3	4	5	6	7
ASPEN STREAM ID	O2CRYO	RCYIN	COALFEED	TOESP	ASH5	ASH6	FLUEGAS
Description	O2 (95%)	RECYCLE	Coalfeed coal	to ESP	Ash Boiler solids	Ash ESP Solids	Fluegas
Temperature F	60	305	59	306	306	306	306
Pressure psi	18	15.1	14.7	14.4	14.4	14.4	14.4
Mass Flow lb/hr	668508	2400581	296097	3359182	6001	24004	3335178
Mole Flow lbmol/hr	20750	68484					95146
Enthalpy MMBtu/hr	-2.6	-8972.6	-1089.7	-12520.7	-14	-55.8	-12464.9
Mole Frac							
O2	0.95000	0.04534		0.04534			0.04534
N2	0.01500	0.01664		0.01664			0.01664
AR	0.03500	0.02725		0.02724			0.02724
CO2		0.58536		0.58536			0.58536
H2O		0.31627		0.31628			0.31628
SO2		0.00868		0.00868			0.00868
CL2		0.00046		0.00046			0.00046
TOTAL	1.00000	1.00000		1.00000			1.00000

FLOW DIA. ID	8	9A	9B	9C	9	11	15
ASPEN STREAM ID	21	FLVAP1	H2OWST	TOSTACK	37	OXIDANT	LIQWST
Description	to FGD	to Flash	H2O-Flash	to Stack	CO2 Prod	Oxid to FGD	Slurry exit 12.2% solids
Temperature F	316.9	129	83.8	129	231	60	129
Pressure psi	15.3	14.7	14.7	14.7	1500	14.7	14.7
Mass Flow lb/hr	934610	828534	49455	60821	779080	59291	299440
Mole Flow lbmol/hr	26663	21012	2745	2222	18267	2055	14910
Enthalpy MMBtu/hr	-3490.3	-2958.9	-339	-29.9	-2677.6	-2.5	-1966
Mole Frac							
O2	0.04534	0.05753	0.00000	0.14394	0.06617	0.20747	7.1496E-07
N2	0.01664	0.02112	0.00000	0.71498	0.02429	0.77316	2.3719E-07
AR	0.02724	0.03457	0.00000	0.00851	0.03976	0.00921	4.0633E-08
CO2	0.58536	0.75289	0.00003	0.00038	0.86603	0.00030	7.7199E-09
H2O	0.31628	0.13243	0.99996	0.13218	0.00206	0.00986	0.999999
SO2	0.00868	0.00088	0.00000	0.00001	0.00101	0.00000	1.3246E-08
CL2	0.00046	0.00058	0.00000	0.00000	0.00067	0.00000	1.3052E-09
TOTAL	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000

FLOW DIAGRAM ID	10	12	13	14	16	17	18
ASPEN STREAM ID	BDWN	LMSTONE	SH2O	H2OMX	H1	H2	H3
description	H2O blowdn	Lmstone 30% solids	H2O - Slurry	H2O - FGD	Steam-HP	Bleed	bld to ip
Temperature F	674.1	60	68	68	1000	1000	1000
Pressure psi	2600	14.7	14.7	14.7	2415	2415	2415
Mass Flow lb/hr	13119	92708	69692	32495	2732657	1082	3786
Mole Flow lbmol/hr	728	3861	3868	1804	151684	60	210
Enthalpy MMBtu/hr	-80.3	-595.6	-478.9	-223.3	-14772.5	-5.9	-20.5
Mole Frac							
H2O	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
TOTAL	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000

FLOW DIAGRAM ID	19	20	21	22	23	24	25
ASPEN STREAM ID	H4	H5	H7	H8	H9	H8A	I2
description	bld to ip	to FWH4	to seal reg	stm->reheat	to FWH7	Reheat->IP	to FWH6
Temperature F	801.6	631.4	655.4	631.4	631.4	1000	811.8
Pressure psi	1207.5	603.6	603.6	603.6	603.6	545.4	278.9
Mass Flow lb/hr	32191	5518	10983	2424399	255780	2424399	81891
Mole Flow lbmol/hr	1787	306	610	134573	14198	134573	4546
Enthalpy MMBtu/hr	-176.6	-30.7	-60.9	-13470.7	-1421.2	-12964.1	-445.3
Mole Frac							
H2O	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
TOTAL	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000

PC Steam Cycle – O2 Boiler/CO2 Capture - Stream Summary

FLOW DIAGRAM ID	26	27	28	29	30	31	32
ASPEN STREAM ID	I3	I4	I5	L1	L2	L3	L4
Description	to Deaerator	to LP Turb	to seal reg	to LP #1	to LP #2	to LP #3	from LP #1
Temperature F	695.1	695.1	695.1	695.1	695.1	695.1	101.7
Pressure psi	174.9	174.9	174.9	174.9	174.9	174.9	1
Mass Flow lb/hr	160762	2213941	3782	866131	1247352	100458	845882
Mole Flow lbmol/hr	8924	122891	210	48077	69238	5576	46953
Enthalpy MMBtu/hr	-883.1	-12162.1	-20.8	-4758	-6852.2	-551.9	-4949.7
Mole Frac							
H2O	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
TOTAL	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000

FLOW DIAGRAM ID	33	34	35	36	37	38	39
ASPEN STREAM ID	L5	L6	L7	L8	L9	L10	S1
Description	to FWH4	to FWH3	to FWH2	to FWH1	from LP #2	from LP #3	to seal reg
Temperature F	479.5	293.2	205.1	172.2	110.7	113.3	625.2
Pressure psi	66.5	24.2	12.8	6.3	1.3	1.4	174.9
Mass Flow lb/hr	125909	68277	64612	118127	834904	100458	14765
Mole Flow lbmol/hr	6989	3790	3586	6557	46344	5576	820
Enthalpy MMBtu/hr	-704.4	-387.8	-369.8	-677	-4860.1	-586.2	-81.6
Mole Frac							
H2O	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
TOTAL	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000

FLOW DIAGRAM ID	40	41	42	43	44	45	46
ASPEN STREAM ID	S2	S3	S4	S5	S6	MK1	C0
Description	to FWH1	to cd reheat	to Deaer	to FWH1	to Deaer	makeup	to Deaer
Temperature F	625.2	625.2	625.2	204.7	113.3	60	106.3
Pressure psi	174.9	174.9	174.9	6.3	1.4	14.7	1.4
Mass Flow lb/hr	9540	2814	2412	127667	2814	13119	394796
Mole Flow lbmol/hr	530	156	134	7086	156	728	21914
Enthalpy MMBtu/hr	-52.7	-15.6	-13.3	-729.8	-19.1	-89.7	-2681.4
Mole Frac							
H2O	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
TOTAL	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000

FLOW DIAGRAM ID	47	48	49	50	51	52	53
ASPEN STREAM ID	CD0	CDA	CD1	CD2	CD3	CD4	CD5
Description	from Cond	Pump cdn	cdn-->FWH1	cdn-->FWH2	cdn-->FWH3	cdn-->FWH4	to Deaer
Temperature F	96.4	96.7	98.3	167.8	199.4	232	293.5
Pressure psi	0.9	330	321	300	250	210	175
Mass Flow lb/hr	2247343	2247343	2247343	2247343	2247343	2247343	2247343
Mole Flow lbmol/hr	124745	124745	124745	124745	124745	124745	124745
Enthalpy MMBtu/hr	-15285.5	-15282.9	-15279.4	-15123.8	-15052.9	-14979.5	-14839.4
Mole Frac							
H2O	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
TOTAL	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000

FLOW DIAGRAM ID	54	55	56	57	58	59	60
ASPEN STREAM ID	C76	C5	P1	P3	P4	P2	C1
Description	to Deaer	From Deaer	to FWH6	to FWH7	to econ	to pc	from FWH1
Temperature F	405.7	365.9	372.3	404.3	485.5	372.3	106.2
Pressure psi	263.8	164.8	2903.3	2620	2758	2903.3	6
Mass Flow lb/hr	337671	2745776	2651596	2651596	2651596	94180	391982
Mole Flow lbmol/hr	18743	152412	147184	147184	147184	5228	21758
Enthalpy MMBtu/hr	-2189.3	-17923.9	-17280.7	-17192.7	-16957.9	-613.8	-2662.3
Mole Frac							
H2O	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
TOTAL	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000

PC Steam Cycle – O2 Boiler/CO2 Capture - Stream Summary

FLOW DIAGRAM ID	61	62	63	64	65	66	
ASPEN STREAM ID	C2	C3	C4	C7	STMEXT	CNDSASU	
Description	from FWH2	From FWH3	from FWH4	from FWH7	to ASU	from ASU	
Temperature F	175.4	206.7	239.1	415.5	695.1	370.7	
Pressure psi	11.9	22.4	62.4	588.5	174.9	174.9	
Mass Flow lb/hr	264315	199704	131427	255780	20249	20249	
Mole Flow lbmol/hr	14672	11085	7295	14198	1124	1124	
Enthalpy MMBtu/hr	-1776.9	-1336.3	-875.1	-1656	-111.2	-132.1	
Mole Frac							
H_2O	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	
TOTAL	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	

POWER SUMMARY - CRYOGENIC ASU

TURBINE SECTION	**POWER KW**
HP TURBINE	-119546.04
IP TURBINE	-102618.99
LP TURBINE #1	-88785.26
LP TURBINE #2	-113054.98
TOTAL TURBINE	**-424005.27**
GENERATOR LOSS	6360.08
NET STEAM TURBINE	**-417645.18**

	POWER KW	
LP Turb #3	-10063.12	(lp turb #3 supplies power for
HP Pump	8627.79	the hp feedwater pump)
extra	-1435.33	

***NOTE - ASPEN sign convention
"-" power produced
"+" power required

DRAFT FANS		
- Primary	small	
- Forced	small	
- Induced		2847.99
TOTAL FANS		**2847.99**

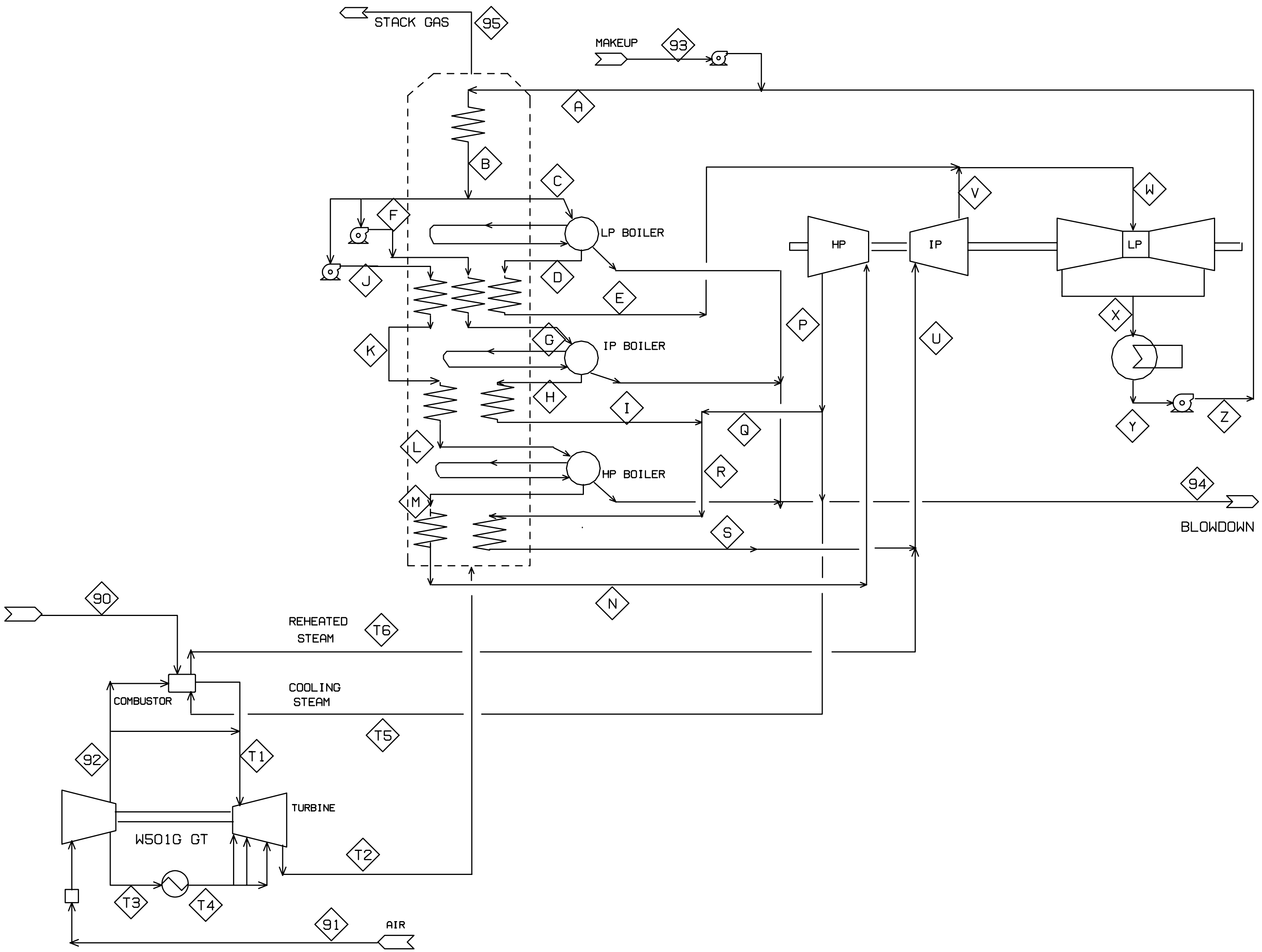
CO2 COMPRESSOR	**33853.73**
WORK ASU	**64299.99**
(ESTIMATE -PRAXAIR)	
MISC WORK	**17468.1567**
CONDENSER PUMP	**755.61**

NET POWER (MWe)	**-298.42**	
COALFEED (LBS/HR)	**296097**	
EFF % (HHV)	**29.48**	INCLUDES CO2 COMPRESSOR
EFF % (HHV)	**32.83**	NO CO2 COMPRESSOR

Combined Cycle

Natural Gas Combined Cycle (NGCC) - No CO_2 Capture

Natural Gas Combined Cycle (NGCC) - No CO_2 Capture



NGCC - W501G GAS TURBINE - 3 PRESSURE LEVEL STEAM CYCLE

	MWe			%
Gas Turbine	266.4	**Efficiency;**		
Steam Turbine	121.9		**LHV**	57.9
Misc/Aux	9.2		**HHV**	52.3
Net Power	379.1			

Stream PFD #	A	B	C	D	E	F	G	H	I	J	K	L
ASPEN Name ID	TOLPEC	HOTLP	TOLPEV	TOLPSH	LPTOIP	TOIPEC	TOIPEV	TOIPSH	FRIPSH	TOHPEC1	TOHPEC2	TOHPEV
Temperature F	92	295	295	299.3	400	296.4	463	472.8	615	299.9	463	615
Pressure psi	73.5	66.3	66.3	66.3	63	585.7	556.4	528.6	518	2263.8	2150.7	2043.1
Mass Flow lb/hr	723086	723086	86061	85201	85201	170371	170371	168667	168667	466654	466654	466654
Mole Flow lbmol/hr	40137	40137	4777	4729	4729	9457	9457	9362	9362	25903	25903	25903
Enthalpy MMBtu/hr	-4921.2	-4773.6	-568.2	-484.5	-480	-1124.3	-1094	-955	-937.7	-3076.4	-2996.3	-2907.1

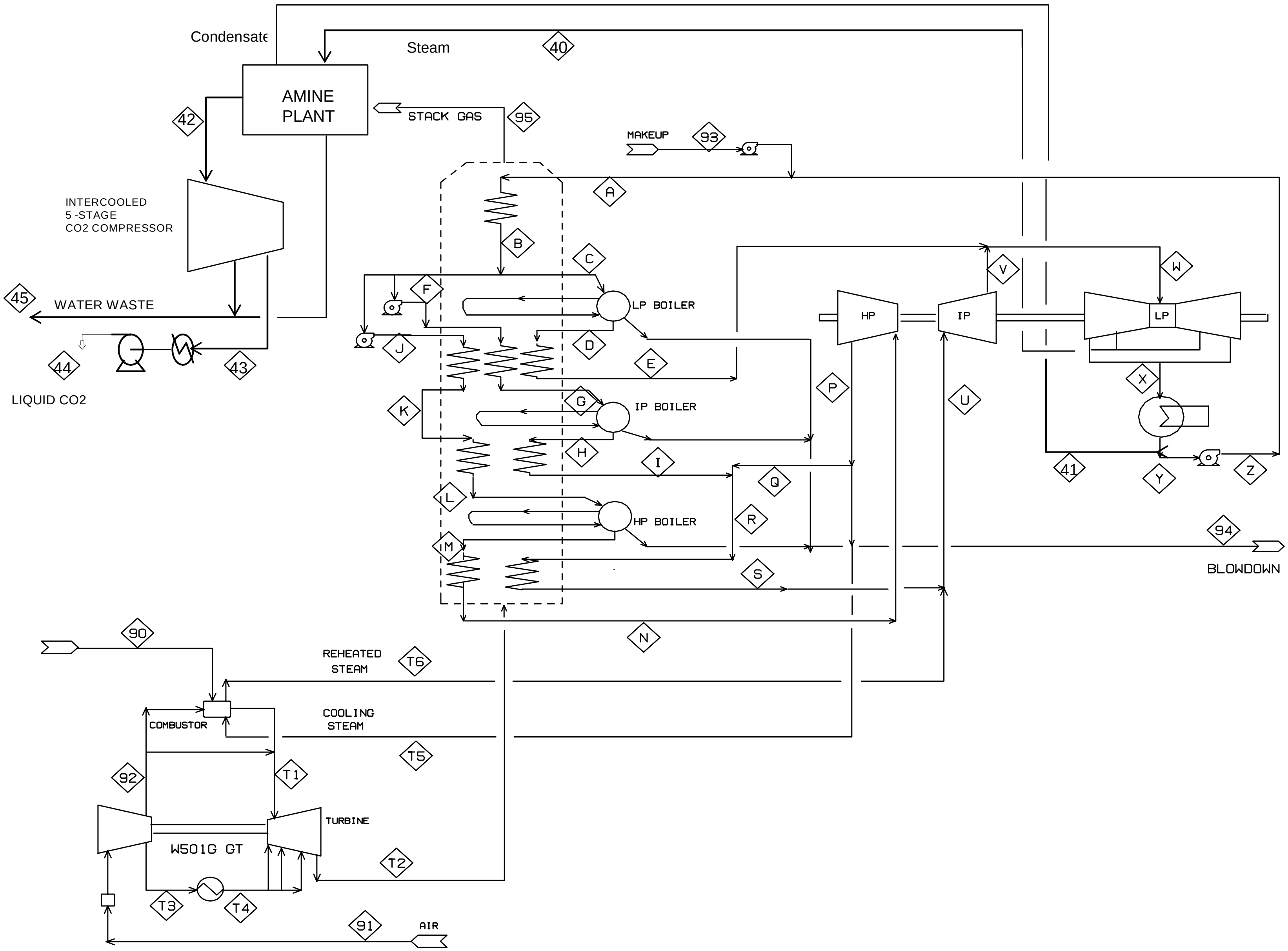
Stream PFD #	M	N	P	Q	R	S	U	V	W	X	Y	Z
ASPEN Name ID	TOHPSH	TOHPTUR	FRHPTUR	TMXIP	TOREHT	52	TOIPTUR1	TOIPMX2	TOIPTUR2	TOCOND	TOCPMP	TOCMIX
Temperature F	631.5	1050	712	712	681.5	1050	1056.8	560.8	541.5	93.6	90	90.1
Pressure psi	1941	1800	518	518	518	492	492	63	63	0.8	0.7	73.5
Mass Flow lb/hr	461987	461987	461987	381987	550654	550654	630654	630654	715855	715855	715855	715855
Mole Flow lbmol/hr	25644	25644	25644	21203	30566	30566	35006	35006	39736	39736	39736	39736
Enthalpy MMBtu/hr	-2644.3	-2474	-2542.3	-2102.1	-3039.8	-2928.8	-3352	-3502.5	-3982.5	-4186	-4873.5	-4873.3

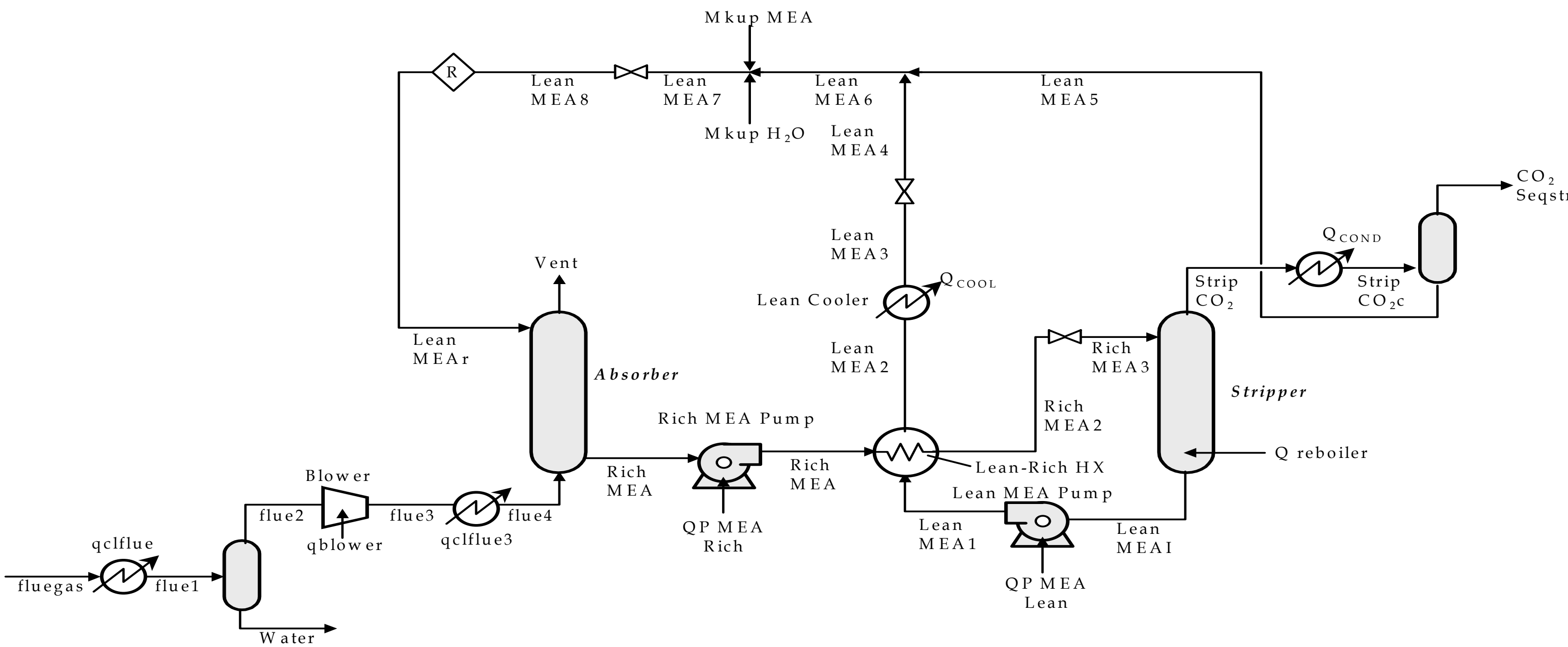
Stream PFD #	90	91	92	93	94	95	T1	T2	T3	T4	T5	T6
ASPEN Name ID	FLH2	1	2	MAKUP	TBLOW	GTPC9	31	33	3	12	C3	C4
Temperature F	200	59	813.2	80	213	208.5	2583	1100.4	813.2	600	712	1103.2
Pressure psi	400	14.7	282.2	20	15	15	268.5	15	282.2	277	518	492
Mass Flow lb/hr	103875	4467600	3933042	7231	7231	4571478	4036920	4571478	527109	527109	80000	80000
Mole Flow lbmol/hr	6475	154822	136297	401	401	161297	142772	161297	18267	18267	4441	4441
Enthalpy MMBtu/hr	-201.3	-186.6	572.4	-49.3	-45.5	-2457.2	342.6	-1367	76.7	47.9	-440.2	-423.2

Combined Cycle

Natural Gas Combined Cycle (NGCC) - CO_2 Capture

NGCC – CO2 CAPTURE





Mkup MEA
R
Lean MEA8
Lean MEA7
Lean MEA6
Lean MEA5
Mkup H_2O
Lean MEA4
CO_2 Seqstr
Lean MEA3
Q_{COOL}
Q_{COND}
Vent
Lean Cooler
Strip CO_2
Strip CO_2c
Lean MEAr
Lean MEA2
Rich MEA3
Absorber
Stripper
Rich MEA Pump
Rich MEA2
Q reboiler
Rich MEA
Rich MEA
Lean-Rich HX
Blower
Lean MEA Pump
flue2
flue3
flue4
qblower
qclflue3
QP MEA Rich
Lean MEA1
Lean MEAI
qclflue
fluegas
flue1
QP MEA Lean
Water

NGCC (WITH CO2 CAPTURE) - W501G GAS TURBINE - 3 PRESSURE LEVEL STEAM CYCLE

	MWe		
Gas Turbine	266.4	**Efficiency;**	%
Steam Turbine	90.7	**LHV**	49.9
Misc/Aux	30.2	**HHV**	45.1
Net Power	326.9		

Stream PFD #	A	B	C	D	E	F	G	H	I	J	K	L
ASPEN Name ID	TOLPEC	FRLPEC	TOLPEV	TOLPSH	LPTOIP	TOIPEC	TOIPEV	TOIPSH	FRIPSH	TOHPEC1	TOHPEC2	TOHPEV
Temperature F	90	295	295	299.3	400	296.4	463	472.8	615	299.9	463	615
Pressure psi	73.5	69.8	69.8	66.3	63	585.7	556.4	528.6	518	2263.8	2150.7	2043.1
Mass Flow lb/hr	721851	721851	84826	83978	83978	170372	170372	168668	168668	466653	466653	466653
Mole Flow lbmol/hr	40068	40068	4709	4661	4661	9457	9457	9362	9362	25903	25903	25903
Enthalpy MMBtu/hr	-4914.2	-4765.5	-560	-477.6	-473.1	-1124.3	-1094	-955	-937.7	-3076.4	-2996.3	-2907.1

Stream PFD #	M	N	P	Q	R	S	U	V	W	X	Y	Z
ASPEN Name ID	TOHPSH	TOHPTUR	FRHPTUR	TMXIP	TOREHT	52	TOIPTUR1	TOIPMX2	TOIPTUR2	TOCOND	TOCPMP	TOCMIX
Temperature F	631.5	1050	712	712	681.5	1050	1056.8	560.8	541.7	93.6	90	90.1
Pressure psi	1941	1800	518	518	518	492	492	63	63	0.8	0.7	73.5
Mass Flow lb/hr	461986	461986	461986	381986	550654	550654	630654	630654	714633	249094	714633	714633
Mole Flow lbmol/hr	25644	25644	25644	21203	30566	30566	35006	35006	39668	13827	39668	39668
Enthalpy MMBtu/hr	-2644.3	-2474	-2542.3	-2102.1	-3039.8	-2928.8	-3352	-3502.5	-3975.6	-1456.6	-4865.2	-4865

Stream PFD #	90	91	92	93	94	95	T1	T2	T3	T4	T5	T6
ASPEN Name ID	FLH2	1	2	MAKUP	TBLOW	GTPC9	31	33	3	12	C3	C4
Temperature F	200	59	813.2	80	213	208.5	2583	1100.4	813.2	600	712	1103.2
Pressure psi	400	14.7	282.2	20	15	15	268.5	15	282.2	277	518	492
Mass Flow lb/hr	103875	4467600	3933042	7219	7219	4571478	4036920	4571478	527109	527109	80000	80000
Mole Flow lbmol/hr	6475	154822	136297	401	401	161297	142772	161297	18267	18267	4441	4441
Enthalpy MMBtu/hr	-201.3	-186.6	572.4	-49.2	-45.5	-2457.3	342.6	-1367	76.7	47.9	-440.2	-423.2

Stream PFD #	40	41	42	43	44	45
ASPEN Name ID	45	53	TCPRCO2	61	62	59
Temperature F	428	250.4	140	245.2	123.1	100
Pressure psi	35	80	25.7	2100	3000	14.7
Mass Flow lb/hr	465539	465539	265986	258518	258518	114659
Mole Flow lbmol/hr	25841	25841	6296	5881	5881	6364
Enthalpy MMBtu/hr	-2614.4	-3094.5	-1033.9	-995.4	-1017.2	-784.5

Combined Cycle

IGCC Destec (E-Gas^{TM}) / CGCU / “G” Gas Turbine

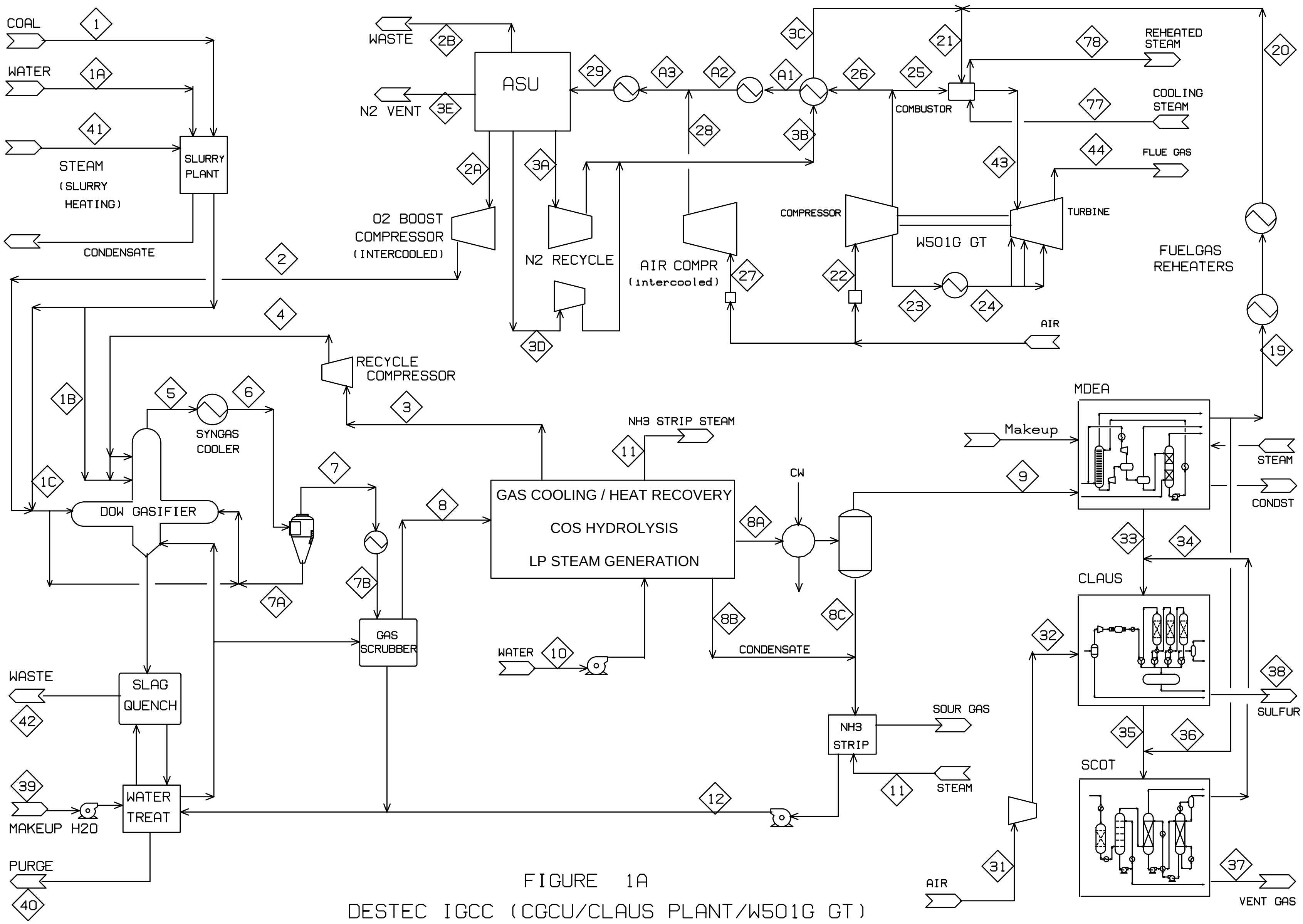


FIGURE 1A

DESTEC IGCC (CGCU/CLAUS PLANT/W501G GT)

DESTEC IGCC - (SYNGAS COOLER / CGCU / CLAUS PLANT / 3 PRES STEAM CYCLE)

SUMMARY:

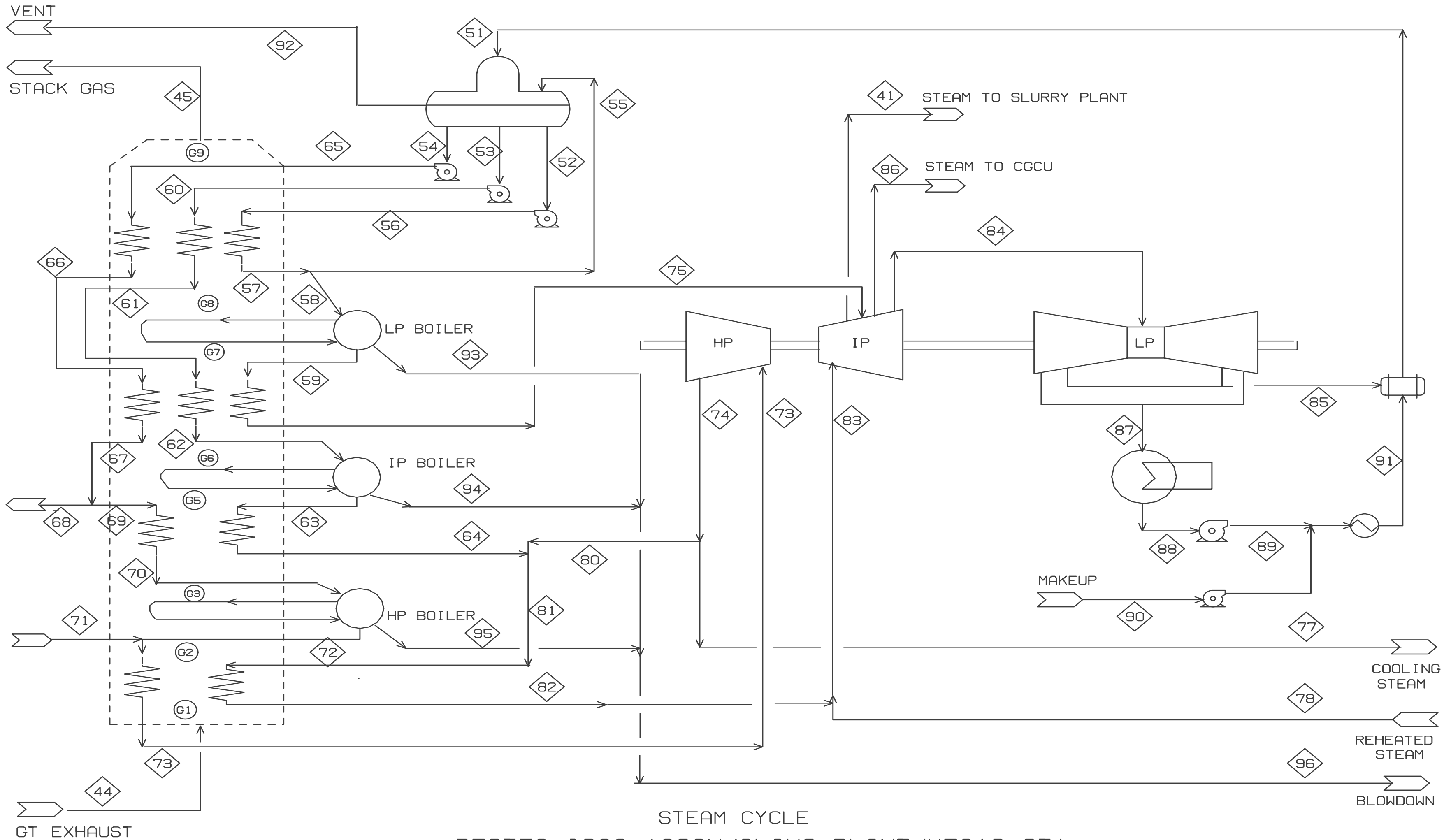
POWER	MWe	EFFICIENCY:		%
GAS TURBINE	272.8		HHV	45
STEAM TURBINE	172.2		LHV	46.7
MISCELLANEOUS	32			
AUXILIAF	12.4			
NET POWER	400.6			

STREAM	1	1A	1B	1C	2A	2B	2	3A	3B	3C	3D	3E	3	4
FLOW (LB/HR)	260226	86709	72573	274362	197846	2990	197846	317975	358735	358735	40761	270868	141102	141103
TEMPERATURE (F)	59	59	350	350	60	59	204.7	62	189.3	700	60	62	304.6	333.8
PRESSURE (PSIA)	14.7	14.7	465	465	92	14.7	472	91	300	294	265	91	378	425
H (MM BTU/HR)	-814.7	-596.7	-153.1	-574.8	-0.9	-20.3	5	-3.5	7.4	54.1	-0.3	-3	-370.7	-369.2

STREAM	5	6	7	7A	7B	8	8A	8B	8C	9	10	11	12	19
FLOW (LB/HR)	670129	670129	661340	8788	661340	705510	472085	92323	11380	460705	45000	45000	102871	424837
TEMPERATURE (F)	1900	650	649.9	649.9	415	304.2	190	232.2	101.9	103	59	280	213	116
PRESSURE (PSIA)	412	403.8	394.5	394.5	390	380	354	354	20	349	14.7	37	470	340
H (MM BTU/HR)	-1164.4	-1519.1	-1506.8	-12.4	-1568	-1853.6	-978	-617.7	-73.3	-931.2	-309.7	-255.7	-690.7	-847.5

STREAM	20	21	22	23	24	25	26	A1	A2	A3	27	28	29	31
FLOW (LB/HR)	424837	783573	4320000	527109	527109	3363310	416102	416102	416102	830440	416102	414338	830440	14107
TEMPERATURE (F)	589.7	629.2	59	813.3	600	813.3	813.3	370.4	216	210	59	203.9	190	59
PRESSURE (PSIA)	330	294	14.6	282.2	276.6	282.2	282.2	280.2	278	278	14.6	278	277	14.7
H (MM BTU/HR)	-770.3	-716.2	-180.3	76.7	47.9	489.6	60.6	13.8	-2.1	4.6	-17.4	6.7	0.5	-0.6

STREAM	32	33	34	35	36	37	38	39	40	41	42	43	44	45
FLOW (LB/HR)	14107	32346	1976	42121	6755	46900	6307	38680	87473	53025	34450	4146881	4673991	4673991
TEMPERATURE (F)	161.2	142.1	70	424	116	70	285	59	200	820.1	200	2582.2	1119.5	261
PRESSURE (PSIA)	25	18.5	17.5	26.7	340	17.5	14.7	14.7	15	150	15	268.5	15.2	14.7
H (MM BTU/HR)	-0.2	-86.3	-6.9	-109.4	-13.5	-126.8	-0.7	-266.2	-585.9	-287.8	-114.7	-265.9	-1971.2	-3032.3



STEAM CYCLE

DESTEC IGCC (CGCU/CLAUS PLANT/W501G GT)

DESTEC IGCC - (SYNGAS COOLER / CGCU / CLAUS PLANT / 3 PRES STEAM CYCLE)

STEAM CYCLE / HRSG PROCESS STREAMS

STREAM	41	44	45	51	52	53	54	55	56	57	58	59	60	61
FLOW (LB/HR)	53025	4673991	4673991	974779	269014	259543	697343	257282	269014	269014	11732	11615	259543	259543
TEMPERATURE (F)	820.1	1119.5	261	203.8	217.3	217.3	217.3	286	217.4	286	286	305.3	218.1	286
PRESSURE (PSIA)	150	15.2	14.7	17	16.3	16.3	16.3	76.3	80.3	76.3	76.3	72.5	410.6	390
H (MM BTU/HR)	-287.8	-1971.2	-3032.3	-6525.4	-1797.2	-1733.9	-4658.8	-1700.9	-1797.1	-1778.4	-77.6	-66	-1733.5	-1715.7

STREAM	62	63	64	65	66	67	68	69	70	71	72	73	74	75
FLOW (LB/HR)	259543	256948	256948	697343	697343	697343	505841	191503	191503	505841	189588	695428	695428	11615
TEMPERATURE (F)	420	432.3	620	221.2	286	420	420	620	620	635	629.3	1050	606.7	420
PRESSURE (PSIA)	370.5	352	350	2345.6	2228.3	2116.9	2116.9	2011.1	2011.1	1910.5	1910.5	1800	350	69.5
H (MM BTU/HR)	-1679.1	-1455	-1424.5	-4652.4	-4607.2	-4510.2	-3271.6	-1191.4	-1191.4	-2888.1	-1084.7	-3724.1	-3860.5	-65.3

STREAM	77	78	80	81	82	83	84	85	86	87	88	89	90	91
FLOW (LB/HR)	70000	70000	625428	882376	882376	952376	849203	23299	61763	825904	825904	825904	125576	951480
TEMPERATURE (F)	606.7	1055.9	606.7	610.6	1050	1050.4	482	350	596.5	88.8	87.9	87.9	80	178.3
PRESSURE (PSIA)	350	342	350	350	342	342	35	17	60	0.7	0.7	40	14.7	17
H (MM BTU/HR)	-388.6	-371.8	-3472	-4896.4	-4689.6	-5061.4	-4746.9	-131.7	-341.9	-4825.3	-5624.5	-5624.4	-856.2	-6393.7

STREAM	92	93	94	95	96	G1	G2	G3	G5	G6	G7	G8	G9
FLOW (LB/HR)	6160	117	2595	1915	4628	4673991	4673991	4673991	4673991	4673991	4673991	4673991	4673991
TEMPERATURE (F)	217.3	305.3	432.3	629.3	213	1119.5	763	686.6	623.4	452	338.9	329.8	260.1
PRESSURE (PSIA)	16.3	72.5	352	1910.5	15	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15
H (MM BTU/HR)	-35.2	-0.8	-16.8	-11.9	-29.4	-1971.2	-2426.8	-2521.6	-2599.2	-2806.6	-2940.8	-2951.6	-3033.4

Combined Cycle

IGCC Destec (E-Gas™) / HGCU / “G” Gas Turbine

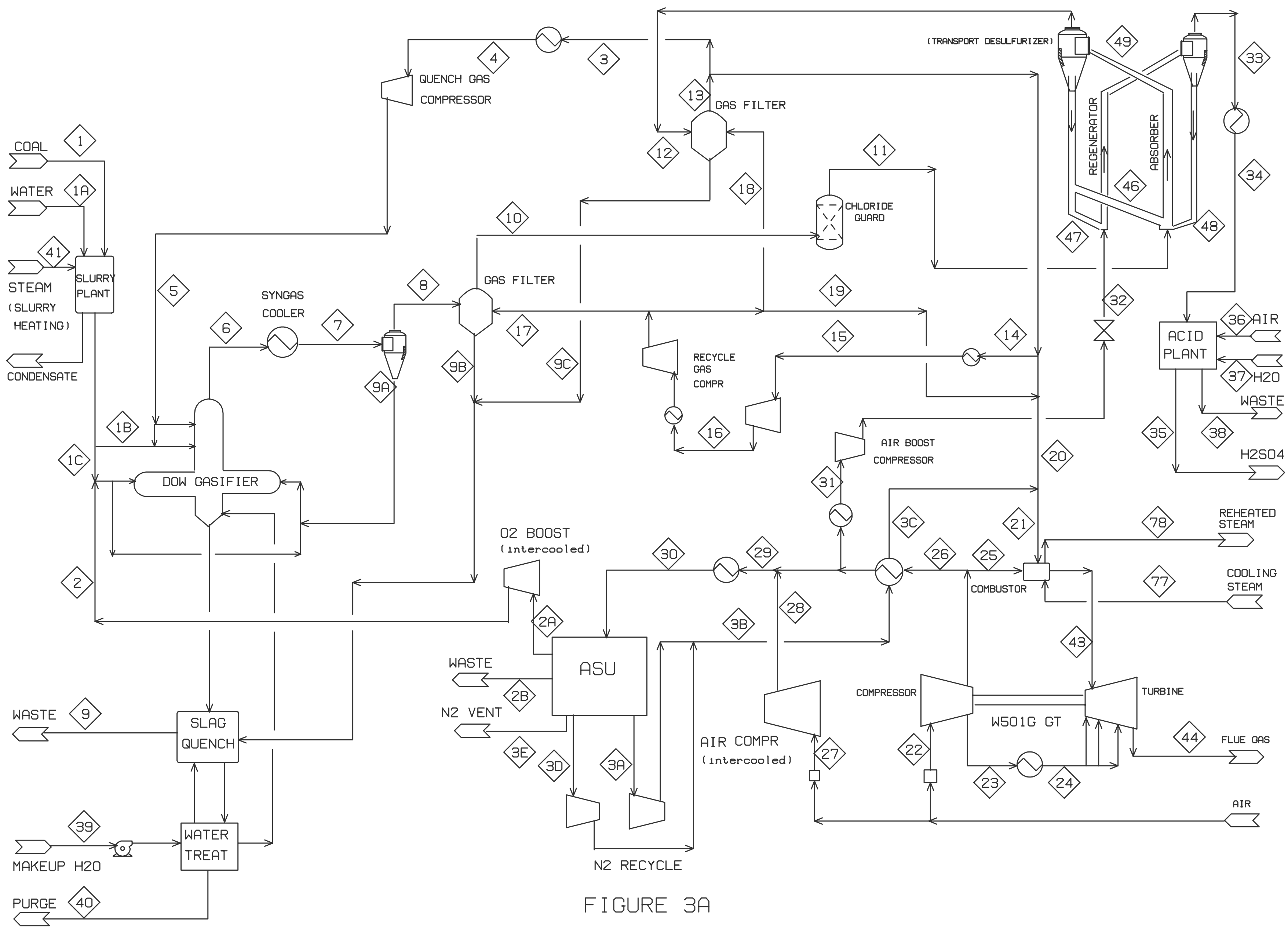


FIGURE 3A

DESTEC IGCC (HGCU/ACID PLANT/W501G GT)

DESTEC IGCC - (SYNGAS COOLER / HGCU / ACIDPLANT / 3 PRES STEAM CYCLE)

SUMMARY:

POWER	MWe	EFFICIENCY:	%
GAS TURBINE	272.6	HHV	47.6
STEAM TURBINE	171.1	LHV	49.4
MISCELLANEOUS	31		
AUXILIAF	12.4		
NET POWER	400.4		

STREAM	1	1A	1B	1C	2A	2B	2	3A	3B	3C	3D	3E	3	4	5
FLOW (LB/HR)	245353	81753	68425	258681	189517	2823	189517	260592	299636	299636	39045	303460	166931	166931	166938
TEMPERATURE (F)	59	59	350	350	60	59	204.7	62	187.3	700	60	62	1053.2	300	360.3
PRESSURE (PSIA)	14.7	14.7	465	465	92	14.7	472	91	300	294	265	91	346	336	425
H (MM BTU/HR)	-768.2	-562.6	-146	-547.8	-0.9	-19.4	4.8	-2.8	6.1	45.3	-0.3	-3.3	-356.7	-406.9	-403.2

STREAM	6	7	8	9A	9B	9C	9	39	40	41	10	11	12	13	14
FLOW (LB/HR)	668707	668707	660421	8286	875	46	36520	29732	17272	50110	667559	666840	663762	667723	13354
TEMPERATURE (F)	1900	1004	1004	1004	997.1	1053.2	200	59	200	820.1	997.1	994.1	1057	1053.2	1053.2
PRESSURE (PSIA)	412	403.8	394.5	394.5	14.7	14.7	14.7	15	15	150	382.7	366	356	346	346
H (MM BTU/HR)	-1152.2	-1408.8	-1397.9	-10.9	-1.2	-0.1	-135.4	-204.6	-116.2	-272	-1416	-1416.1	-1417.3	-1426.8	-28.5

STREAM	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29
FLOW (LB/HR)	13354	13354	8013	4006	1335	488773	788409	4320000	527109	527109	3321623	457790	397907	396217	794125
TEMPERATURE (F)	300	436.2	418.3	418.3	418.3	1051.5	952.5	59	812.7	600	812.7	812.7	59	203.7	341
PRESSURE (PSIA)	336	565.6	900	900	900	345	294	14.6	282.2	276.6	282.2	282.2	14.6	278	278
H (MM BTU/HR)	-32.6	-31.9	-19.2	-9.6	-3.2	-1044.8	-999.4	-180.3	76.8	48	483.7	66.7	-16.6	6.5	30.3

STREAM	30	31	32	33	34	35	36	37	38	43	44	46	47	48	49
FLOW (LB/HR)	794125	59882	59882	62927	62927	18585	13188	3331	60858	4110031	4637140	4390982	487887	484842	5542664
TEMPERATURE (F)	190	120	167	1420.4	850	100	59	59	100	2583	1125.6	1055	1055	1420.4	1057.9
PRESSURE (PSIA)	275	275.2	371	361	344	16	14.7	14.7	16	268.5	15.2	356	356	361	361
H (MM BTU/HR)	0.6	-1.9	-1.1	-5.7	-14.9	-23.3	-0.6	-22.9	-1.9	-554.2	-2259.1	-15077.6	-1675.3	-1672.7	-18166.3

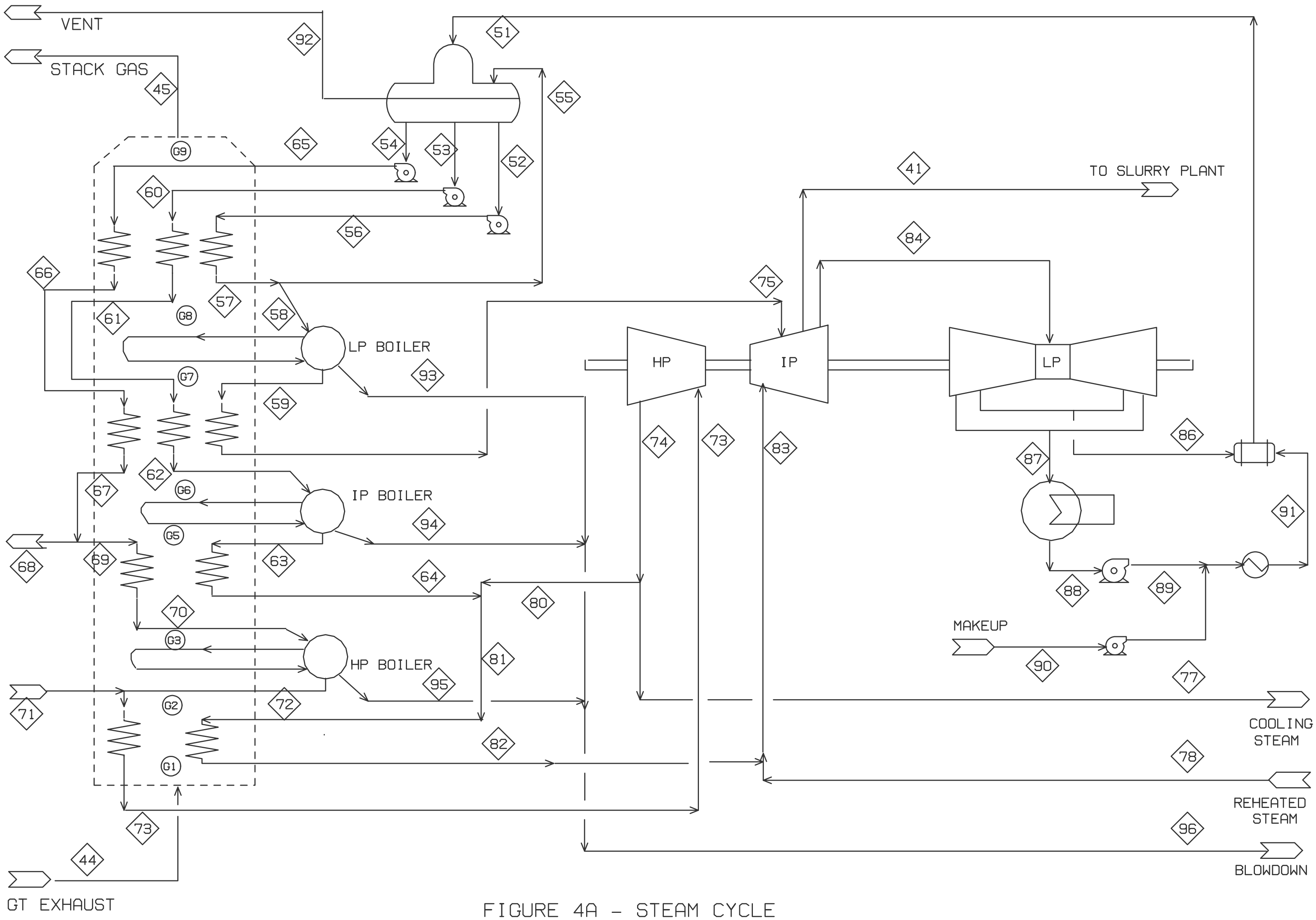


FIGURE 4A – STEAM CYCLE

DESTEC IGCC (HGCU/ACID PLANT/W501G GT)

DESTEC IGCC - (SYNGAS COOLER / HGCU / ACID PLANT / 3 PRES STEAM CYCLE)

STEAM CYCLE / HRSG PROCESS STREAMS

STREAM	41	44	45	51	52	53	54	55	56	57	58	59	60	61
FLOW (LB/HR)	50110	4637140	4637140	950123	262206	263059	669625	250771	262206	262206	11435	11321	263059	263059
TEMPERATURE (F)	820.1	1125.6	258.2	205	217.3	217.3	217.3	286	217.4	286	286	305.3	218.1	286
PRESSURE (PSIA)	150	15.2	15	17	16.3	16.3	16.3	76.3	80.3	76.3	76.3	72.5	410.6	390
H (MM BTU/HR)	-272	-2259.1	-3333.4	-6359.2	-1751.7	-1757.4	-4473.6	-1657.8	-1751.7	-1733.4	-75.6	-64.4	-1757	-1738.9

STREAM	62	63	64	65	66	67	68	69	70	71	72	73	74	75
FLOW (LB/HR)	263059	260428	260428	669625	669625	669625	437666	231959	231959	437666	229639	667305	667305	11321
TEMPERATURE (F)	420	432.3	620	221.2	286	420	420	420	620	635	629.3	1049.3	606.2	420
PRESSURE (PSIA)	370.5	352	350	2345.6	2228.3	2116.9	2116.9	2116.9	2011.1	1911	1910.5	1800	350	69.5
H (MM BTU/HR)	-1701.8	-1474.7	-1443.8	-4467.5	-4424.1	-4330.9	-2830.7	-1500.2	-1443.1	-2498.9	-1313.9	-3573.8	-3704.6	-63.7

STREAM	77	78	80	81	82	83	84	86	87	88	89	90	91	92
FLOW (LB/HR)	70000	70000	597305	857733	857733	927733	888944	51176	837768	837768	837768	61179	898947	6004
TEMPERATURE (F)	606.2	1055.4	606.2	610.4	1050	1050.4	481.9	350	88.8	87.9	87.9	80	145.7	217.3
PRESSURE (PSIA)	350	342	350	350	342	342	35	17	0.7	0.7	40	14.7	17	16.3
H (MM BTU/HR)	-388.6	-371.8	-3316	-4759.8	-4558.6	-4930.5	-4969	-289.2	-4894.6	-5705.3	-5705.2	-417.1	-6070.1	-34.3

STREAM	93	94	95	96	G1	G2	G3	G5	G6	G7	G8	G9
FLOW (LB/HR)	114	2631	2320	5065	4637140	4637140	4637140	4637140	4637140	4637140	4637140	4637140
TEMPERATURE (F)	305.3	432.3	629.3	213	1125.6	782.5	690.3	618.8	445.1	335	326.1	258.2
PRESSURE (PSIA)	72.5	352	1910.5	15	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15
H (MM BTU/HR)	-0.8	-17	-14.4	-32.1	-2259.1	-2699.3	-2814.1	-2902.1	-3112.3	-3243.2	-3253.7	-3333.4

Combined Cycle

IGCC Destec (E-Gas™) / CGCU / "G" Gas Turbine / CO_2 Capture

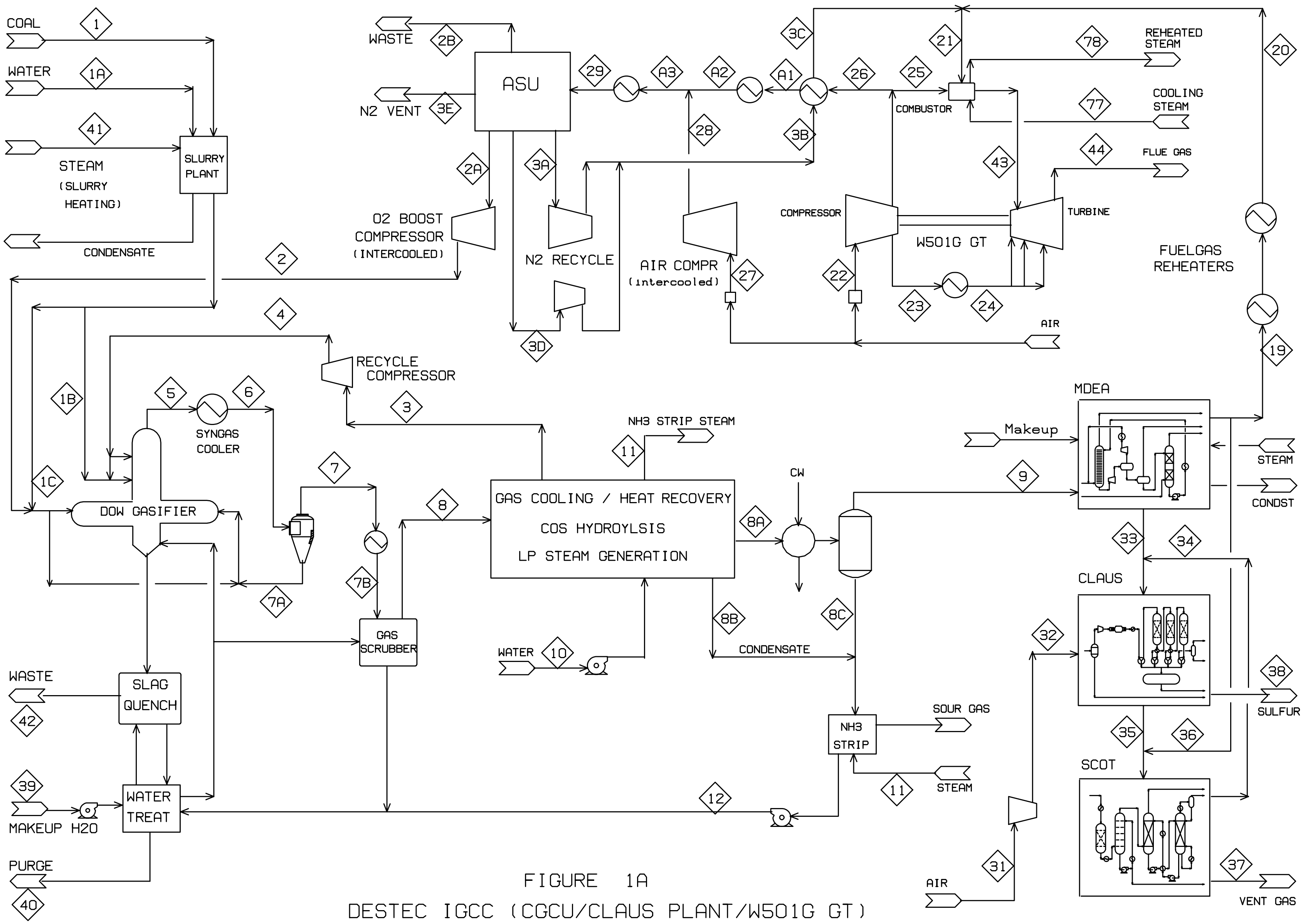


FIGURE 1A

DESTEC IGCC (CGCU/CLAUS PLANT/W501G GT)

DESTEC IGCC - (SYNGAS COOLER / CGCU / CLAUS PLANT / 3 PRES STEAM CYCLE)

SUMMARY:

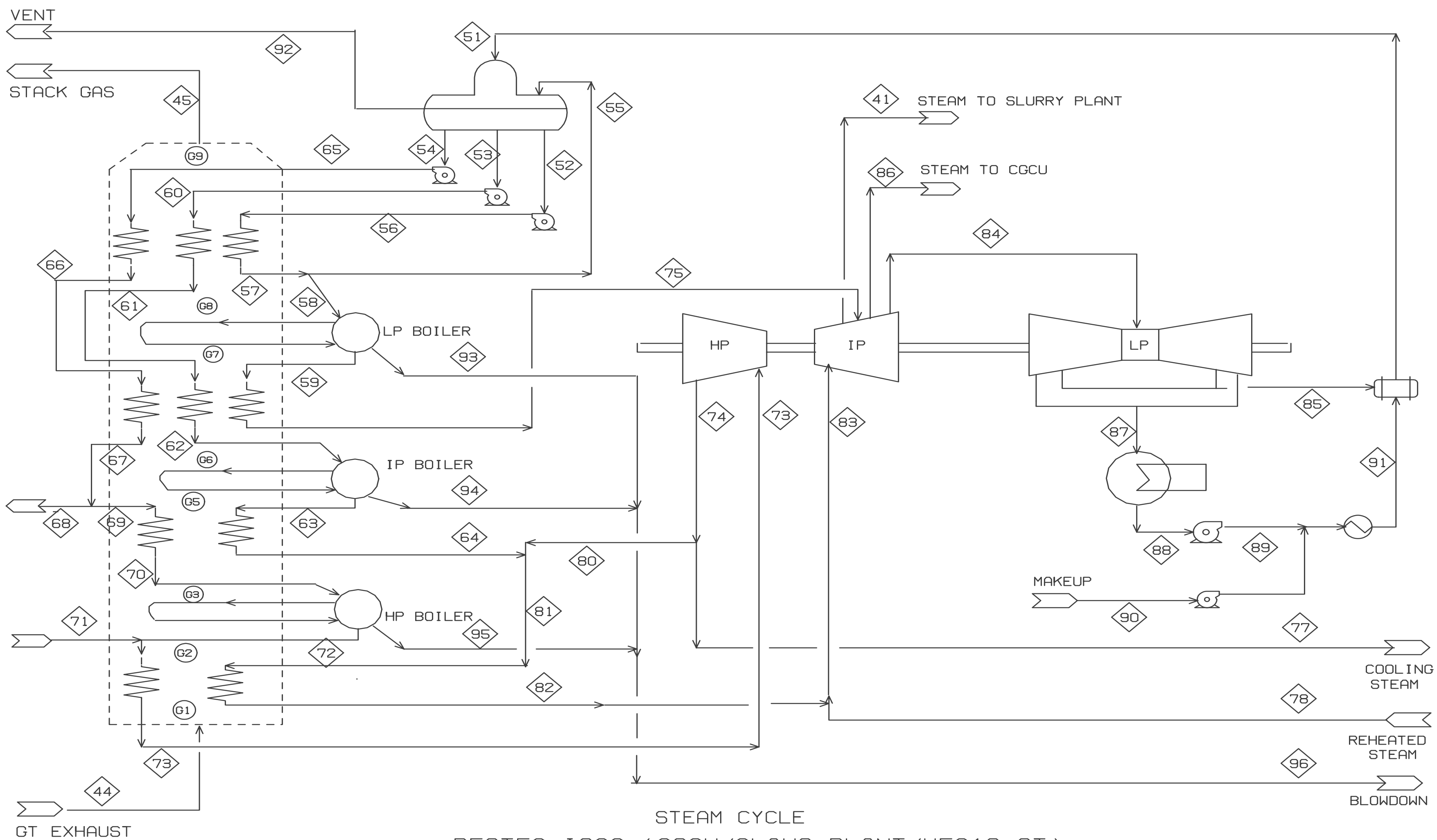
POWER	MWe	EFFICIENCY:	%
GAS TURBINE	272.8	HHV	45
STEAM TURBINE	172.2	LHV	46.7
MISCELLANEOUS	32		
AUXILIAF	12.4		
NET POWER	400.6		

STREAM	1	1A	1B	1C	2A	2B	2	3A	3B	3C	3D	3E	3	4
FLOW (LB/HR)	260226	86709	72573	274362	197846	2990	197846	317975	358735	358735	40761	270868	141102	141103
TEMPERATURE (F)	59	59	350	350	60	59	204.7	62	189.3	700	60	62	304.6	333.8
PRESSURE (PSIA)	14.7	14.7	465	465	92	14.7	472	91	300	294	265	91	378	425
H (MM BTU/HR)	-814.7	-596.7	-153.1	-574.8	-0.9	-20.3	5	-3.5	7.4	54.1	-0.3	-3	-370.7	-369.2

STREAM	5	6	7	7A	7B	8	8A	8B	8C	9	10	11	12	19
FLOW (LB/HR)	670129	670129	661340	8788	661340	705510	472085	92323	11380	460705	45000	45000	102871	424837
TEMPERATURE (F)	1900	650	649.9	649.9	415	304.2	190	232.2	101.9	103	59	280	213	116
PRESSURE (PSIA)	412	403.8	394.5	394.5	390	380	354	354	20	349	14.7	37	470	340
H (MM BTU/HR)	-1164.4	-1519.1	-1506.8	-12.4	-1568	-1853.6	-978	-617.7	-73.3	-931.2	-309.7	-255.7	-690.7	-847.5

STREAM	20	21	22	23	24	25	26	A1	A2	A3	27	28	29	31
FLOW (LB/HR)	424837	783573	4320000	527109	527109	3363310	416102	416102	416102	830440	416102	414338	830440	14107
TEMPERATURE (F)	589.7	629.2	59	813.3	600	813.3	813.3	370.4	216	210	59	203.9	190	59
PRESSURE (PSIA)	330	294	14.6	282.2	276.6	282.2	282.2	280.2	278	278	14.6	278	277	14.7
H (MM BTU/HR)	-770.3	-716.2	-180.3	76.7	47.9	489.6	60.6	13.8	-2.1	4.6	-17.4	6.7	0.5	-0.6

STREAM	32	33	34	35	36	37	38	39	40	41	42	43	44	45
FLOW (LB/HR)	14107	32346	1976	42121	6755	46900	6307	38680	87473	53025	34450	4146881	4673991	4673991
TEMPERATURE (F)	161.2	142.1	70	424	116	70	285	59	200	820.1	200	2582.2	1119.5	261
PRESSURE (PSIA)	25	18.5	17.5	26.7	340	17.5	14.7	14.7	15	150	15	268.5	15.2	14.7
H (MM BTU/HR)	-0.2	-86.3	-6.9	-109.4	-13.5	-126.8	-0.7	-266.2	-585.9	-287.8	-114.7	-265.9	-1971.2	-3032.3



STEAM CYCLE

DESTEC IGCC (CGCU/CLAUS PLANT/W501G GT)

DESTEC IGCC - (SYNGAS COOLER / CGCU / CLAUS PLANT / 3 PRES STEAM CYCLE)

STEAM CYCLE / HRSG PROCESS STREAMS

STREAM	41	44	45	51	52	53	54	55	56	57	58	59	60	61
FLOW (LB/HR)	53025	4673991	4673991	974779	269014	259543	697343	257282	269014	269014	11732	11615	259543	259543
TEMPERATURE (F)	820.1	1119.5	261	203.8	217.3	217.3	217.3	286	217.4	286	286	305.3	218.1	286
PRESSURE (PSIA)	150	15.2	14.7	17	16.3	16.3	16.3	76.3	80.3	76.3	76.3	72.5	410.6	390
H (MM BTU/HR)	-287.8	-1971.2	-3032.3	-6525.4	-1797.2	-1733.9	-4658.8	-1700.9	-1797.1	-1778.4	-77.6	-66	-1733.5	-1715.7

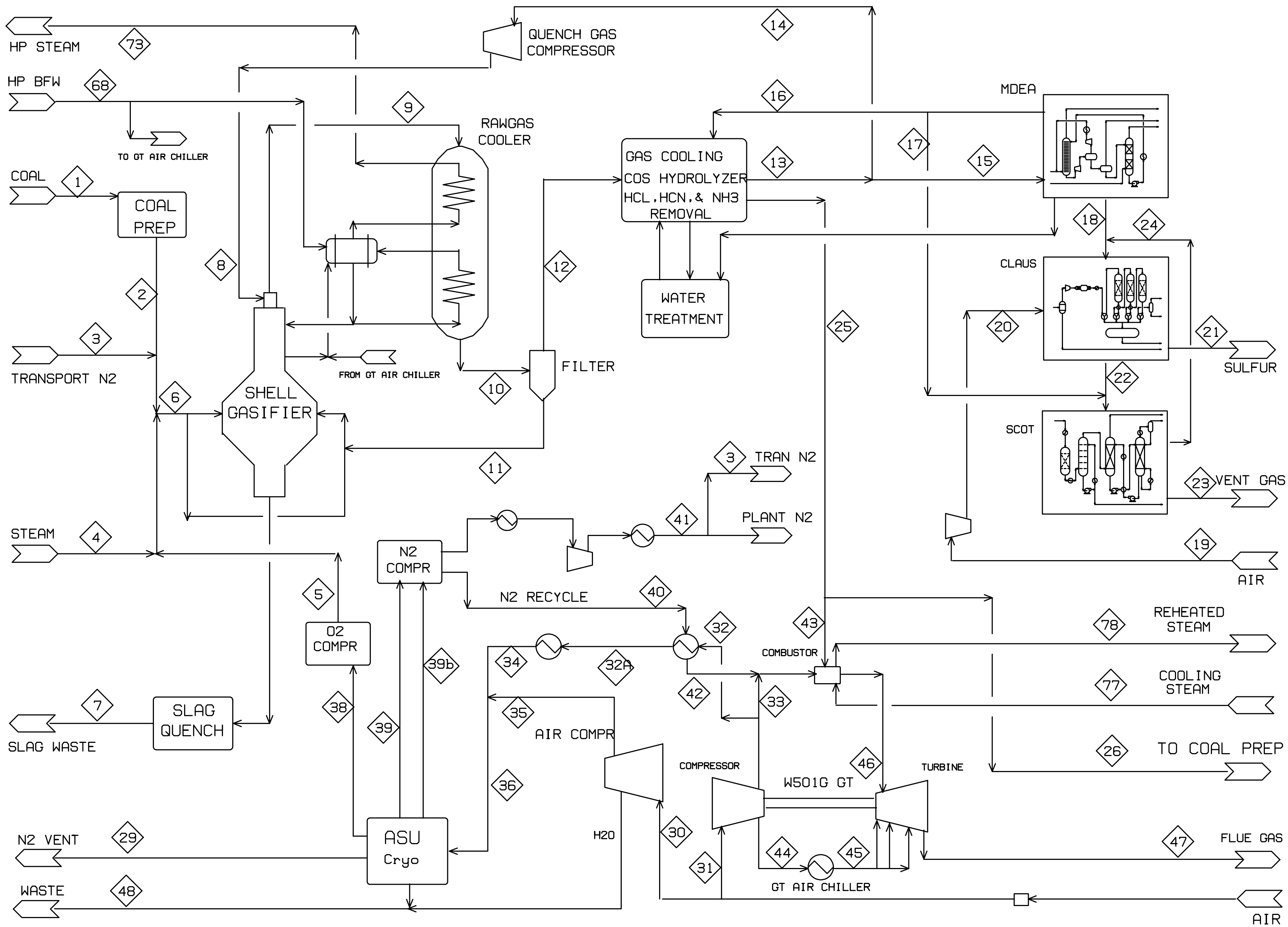
STREAM	62	63	64	65	66	67	68	69	70	71	72	73	74	75
FLOW (LB/HR)	259543	256948	256948	697343	697343	697343	505841	191503	191503	505841	189588	695428	695428	11615
TEMPERATURE (F)	420	432.3	620	221.2	286	420	420	620	620	635	629.3	1050	606.7	420
PRESSURE (PSIA)	370.5	352	350	2345.6	2228.3	2116.9	2116.9	2011.1	2011.1	1910.5	1910.5	1800	350	69.5
H (MM BTU/HR)	-1679.1	-1455	-1424.5	-4652.4	-4607.2	-4510.2	-3271.6	-1191.4	-1191.4	-2888.1	-1084.7	-3724.1	-3860.5	-65.3

STREAM	77	78	80	81	82	83	84	85	86	87	88	89	90	91
FLOW (LB/HR)	70000	70000	625428	882376	882376	952376	849203	23299	61763	825904	825904	825904	125576	951480
TEMPERATURE (F)	606.7	1055.9	606.7	610.6	1050	1050.4	482	350	596.5	88.8	87.9	87.9	80	178.3
PRESSURE (PSIA)	350	342	350	350	342	342	35	17	60	0.7	0.7	40	14.7	17
H (MM BTU/HR)	-388.6	-371.8	-3472	-4896.4	-4689.6	-5061.4	-4746.9	-131.7	-341.9	-4825.3	-5624.5	-5624.4	-856.2	-6393.7

STREAM	92	93	94	95	96	G1	G2	G3	G5	G6	G7	G8	G9
FLOW (LB/HR)	6160	117	2595	1915	4628	4673991	4673991	4673991	4673991	4673991	4673991	4673991	4673991
TEMPERATURE (F)	217.3	305.3	432.3	629.3	213	1119.5	763	686.6	623.4	452	338.9	329.8	260.1
PRESSURE (PSIA)	16.3	72.5	352	1910.5	15	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15
H (MM BTU/HR)	-35.2	-0.8	-16.8	-11.9	-29.4	-1971.2	-2426.8	-2521.6	-2599.2	-2806.6	-2940.8	-2951.6	-3033.4

Combined Cycle

IGCC Shell / CGCU / “G” Gas Turbine



SHELL IGCC CGCU - BASE CASE

FIGURE 1B

SHELL IGCC CGCU - BASE CASE

SUMMARY :

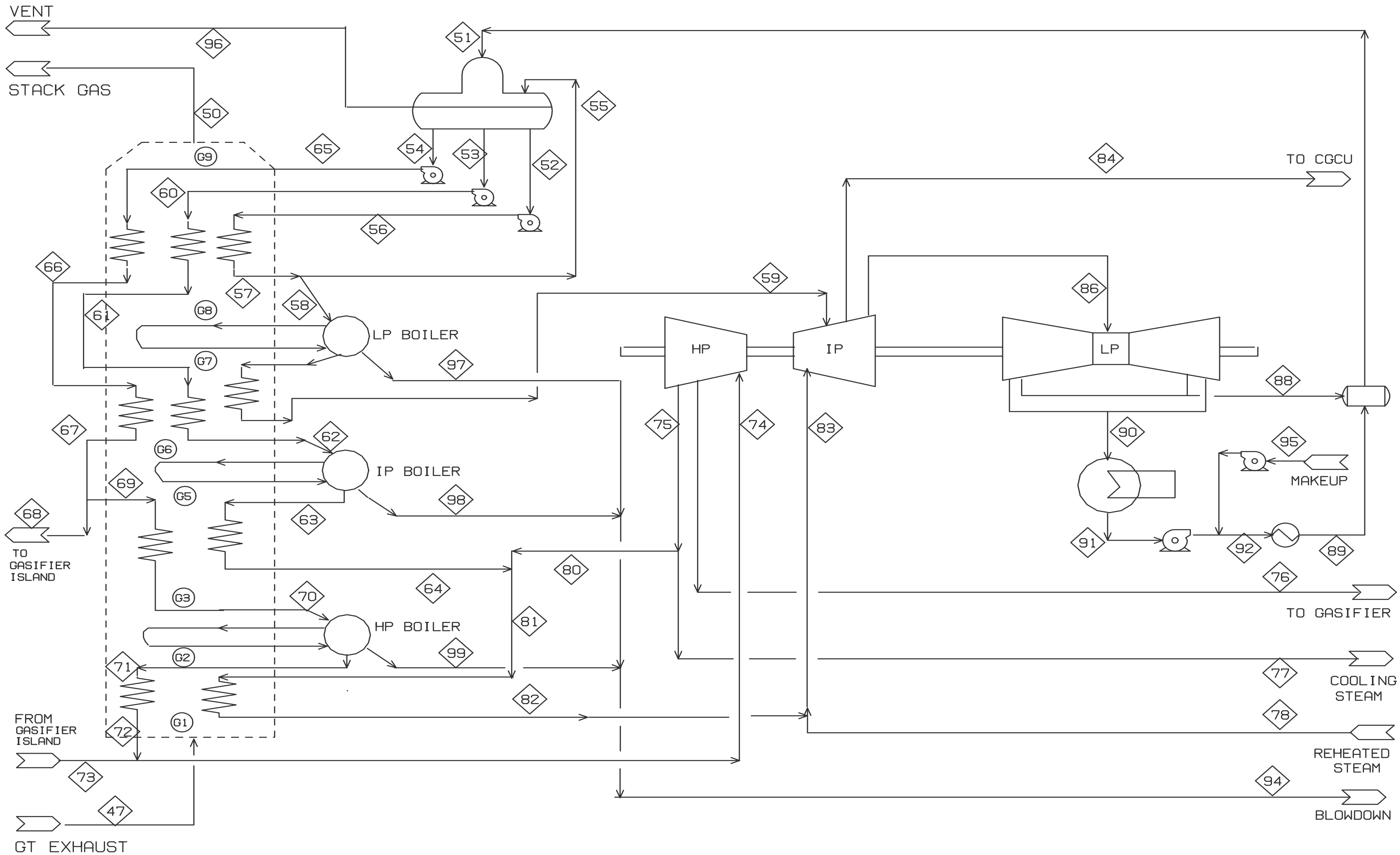
POWER	MWe	EFFICIENCY:	%
GAS TURBINE	272.3	HHV	45.7
STEAM TURBINE	188.9	LHV	47.4
MISCELLANEOUS	35.5		
AUXILIARY (3%)	12.8		
PLANT TOTAL	412.8		

STREAM	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
FLOW (LB/HR)	264263	248089	18971	7214	213207	488857	26747	194116	656226	656226	1408	654818	647053	194116	452937
TEMPERATURE (F)	59	59	104	694	204.7	144.9	300	123.9	1843.7	640	640	640	100	100	100
PRESSURE (PSIA)	14.7	14.7	400	500	472	370	14.7	370	352.5	347.5	347.5	342.5	327.5	327.5	327.5
H (MM BTU/HR)	-972.6	-155.9	0.1	-39.8	5.4	-193	-62.3	-311.6	-669.3	-964.7	-3.1	-961.6	-1043.9	-313.2	-730.7

STREAM	16	17	18	19	20	21	22	23	24	25	26	29	30	31	32
FLOW (LB/HR)	435249	7243	12078	14529	14529	6496	20730	27354	619	435249	3174	234788	448410	4320000	448410
TEMPERATURE (F)	116	116	160.3	59	161.2	285	430.8	70	70	600	600	62	59	59	813.3
PRESSURE (PSIA)	323	323	18.5	14.7	25	14.7	26.7	17.5	17.5	318	318	91	14.6	14.6	282.2
H (MM BTU/HR)	-701.6	-11.7	-24.2	-0.6	-0.2	-0.7	-44.2	-62.4	-1.7	-628.4	-4.6	-2.6	-18.7	-180.3	65.3

STREAM	32A	33	34	35	36	38	39	39B	40	41	42	43	44	45	46
FLOW (LB/HR)	448410	3331003	448410	446508	894918	213207	399775	43925	415244	28456	415244	432075	527109	527109	4178319
TEMPERATURE (F)	334.1	813.3	190	203.9	196.9	60	62	60	198.7	105	712	600	813.3	600	2583.1
PRESSURE (PSIA)	280.2	282.2	278	278	278	92	91	265	300	401.8	294	318	282.2	276.6	268.5
H (MM BTU/HR)	10.8	484.8	-5.2	7.3	2.1	-1	-4.4	-0.3	9.3	0.1	63.8	-623.8	76.7	47.9	-114.6

STREAM	47	48	68	73	77	78
FLOW (LB/HR)	4705428	5124	440022	440022	70000	70000
TEMPERATURE (F)	1117.5	59	420	1050	606.2	1055.4
PRESSURE (PSIA)	15.2	15	2116.9	1815	350	342
H (MM BTU/HR)	-1818.1	-35	-2845.9	-2356.5	-388.6	-371.8



SHELL IGCC CGCU – STEAM CYCLE – BASE CASE

Shell IGCC CGCU - Steam Cycle /HRSG Streams

STREAM	47	50	51	52	53	54	55	56	57	58	59	60	61	62	63
FLOW (LB/HR)	4705428	4705428	1034798	285578	199288	816516	273123	285578	285578	12454	12330	199288	199288	199288	197295
TEMPERATURE (F)	1117.5	260	205	217.3	217.3	217.3	286	217.4	286	286	420	218.1	286	420	432.3
PRESSURE (PSIA)	15.2	14.7	17	16.3	16.3	16.3	76.3	80.3	76.3	76.3	70.5	410.6	390	370.5	352
H (MM BTU/HR)	-1818.1	-2876	-6925.9	-1907.9	-1331.4	-5454.9	-1805.6	-1907.8	-1887.9	-82.3	-69.3	-1331	-1317.4	-1289.3	-1117.2

STREAM	64	65	66	67	68	69	70	71	72	73	74	75	76	77	78
FLOW (LB/HR)	197295	816516	816516	816516	440022	376494	376494	372729	372729	440022	812751	805536	7214	70000	70000
TEMPERATURE (F)	620	221.1	286	420	420	420	620	629.3	1050	1050	1049.3	606.2	695.7	606.2	1055.4
PRESSURE (PSIA)	350	2345.6	2228.3	2116.9	2116.9	2116.9	2011.1	1910.5	1815	1815	1800	350	510	350	342
H (MM BTU/HR)	-1093.8	-5447.6	-5394.5	-5281	-2845.9	-2435	-2342.3	-2132.6	-1996.2	-2356.5	-4352.7	-4472	-39.8	-388.6	-371.8

STREAM	80	81	82	83	84	86	88	89	90	91	92	94	95	96	97
FLOW (LB/HR)	735536	932832	932832	1002832	86350	928812	50648	984150	878164	878164	984150	5882	105986	6540	125
TEMPERATURE (F)	606.2	609.1	1050	1050.4	600	485.1	352.8	151.6	88.8	87.9	87	213	80	217.3	305.3
PRESSURE (PSIA)	350	350	342	342	60	35	17	17	0.7	0.7	17	15	14.7	16.3	72.5
H (MM BTU/HR)	-4083.4	-5177.2	-4957.8	-5329.6	-477.9	-5190.4	-286.1	-6639.6	-5129.8	-5980.4	-6702.9	-37	-722.6	-37.4	-0.8

STREAM	98	99	G1	G2	G3	G5	G6	G7	G8	G9
FLOW (LB/HR)	1993	3765	4705428	4705428	4705428	4705428	4705428	4705428	4705428	4705428
TEMPERATURE (F)	432.3	629.3	1117.5	839.9	690.3	595.5	463.5	343.6	333.9	259.9
PRESSURE (PSIA)	352	1910.5	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15
H (MM BTU/HR)	-12.9	-23.4	-1818.1	-2174	-2360.4	-2476.5	-2635.7	-2778.1	-2789.5	-2876.1

Combined Cycle

IGCC Shell / CGCU / “G” Gas Turbine / CO_2 Capture

Material & Energy Balance

Results by ANL : (J. Molburg, R. Doctor , N. Brockmeier)

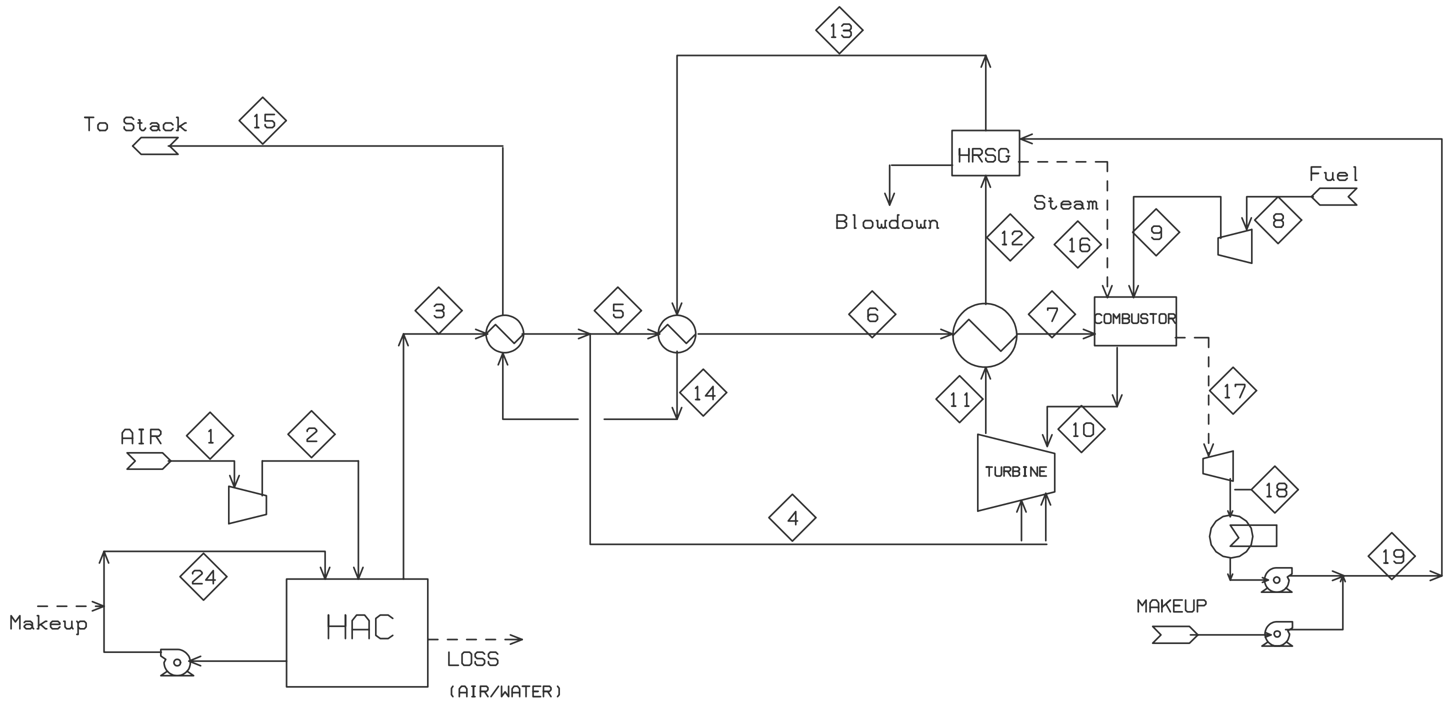
Are storied on

NETL/Gasification Technologies team website (Publications) :
http://www.netl.doe.gov/coalpower/gasification/pubs/pdf/igcc-co2.pdf

Hydraulic Air Compression (HAC)

Natural Gas HAC - No CO_2 Capture

HYDRAULIC AIR COMPRESSION CYCLE - NATURAL GAS - NO CO2 SEQUESTRATION



HYDRAULIC AIR COMPRESSION CYCLE - NATURAL GAS - NO CO2 SEQUESTRATION

	MWe	EFFICIENCY		%
GT EXPANDER	323.5		LHV	53.2
STEAM TURBINE	6.1		HHV	48.1
HAC	170.7			
MISC/AUX	6.6			
NET POWER	323.5			

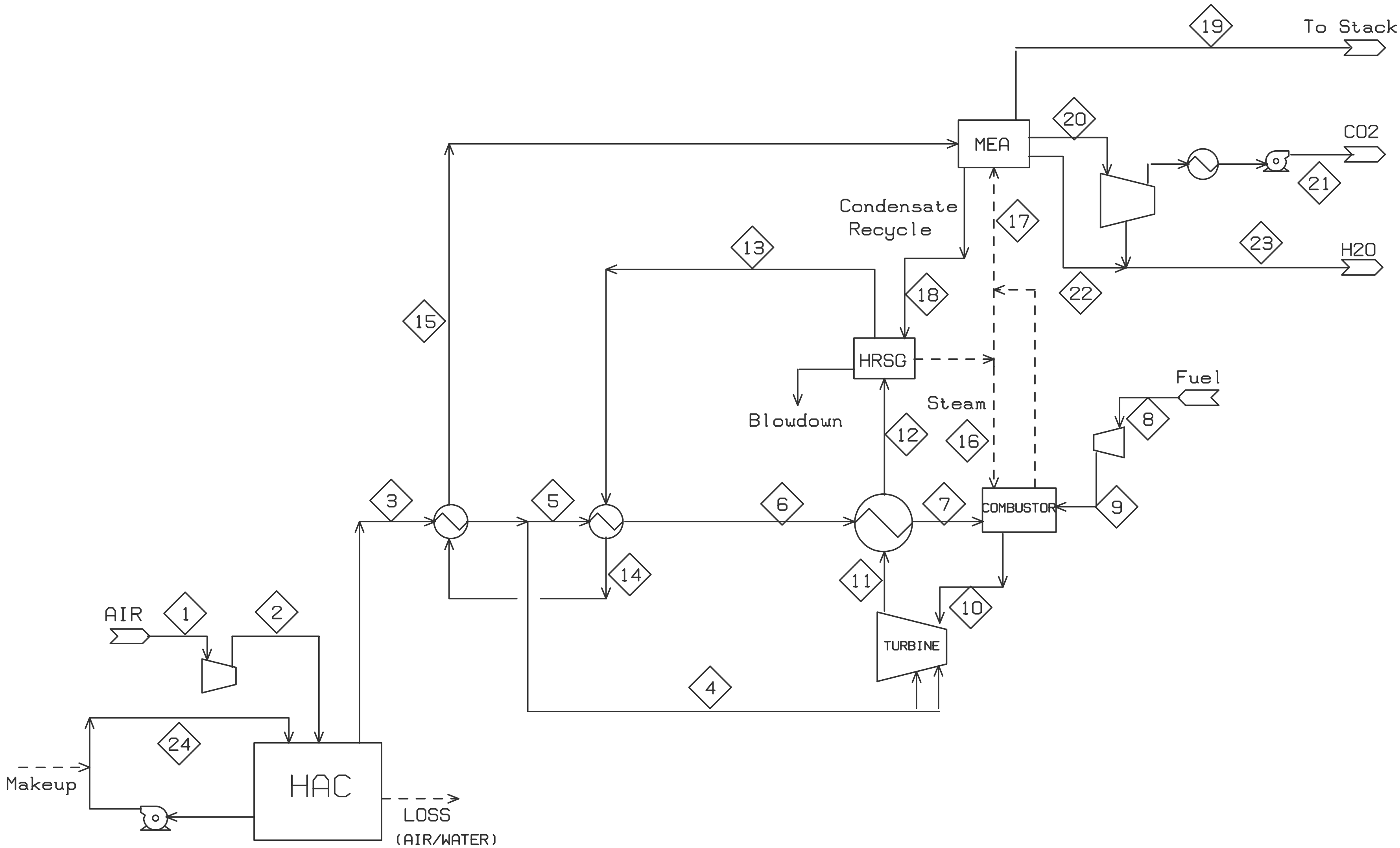
STREAM ID	1	2	3	4	5	6	7	8	9	10
Mass Flow lb/hr	4203605	4203605	4196597	263544	3933053	3933053	3933053	96465	96465	4029509
Temperature F	59	66	60	100	100	175	950	60	191.6	2583
Pressure psi	14.7	15.3	282	277.9	277.9	273.8	273.8	150	350	268.5
H MMBtu/hr	-175.6	-168.5	-209.9	-10.1	-150.4	-59.9	713.2	-194	-187.4	498.5

STREAM ID	11	12	13	14	15	16	17	18	19	24
Mass Flow lb/hr	4293063	4293063	4293063	4293063	4293063	80000	80000	80000	80808	4690215160
Temperature F	1127.9	479.4	400	318	273	265	699.1	131.2	96.1	59
Pressure psi	15.2	14.9	14.9	14.8	14.7	35	30	1	40	58.6
H MMBtu/hr	-1225.5	-1983.2	-2071.8	-2162.3	-2211.7	-455.7	-438.7	-459.8	-549.6	-3.21E+07

Hydraulic Air Compression (HAC)

Natural Gas HAC - CO_2 Capture

HYDRAULIC AIR COMPRESSION CYCLE - NATURAL GAS - CO2 SEQUESTRATION



HYDRAULIC AIR COMPRESSION CYCLE - NATURAL GAS - CO2 SEQUESTRATION

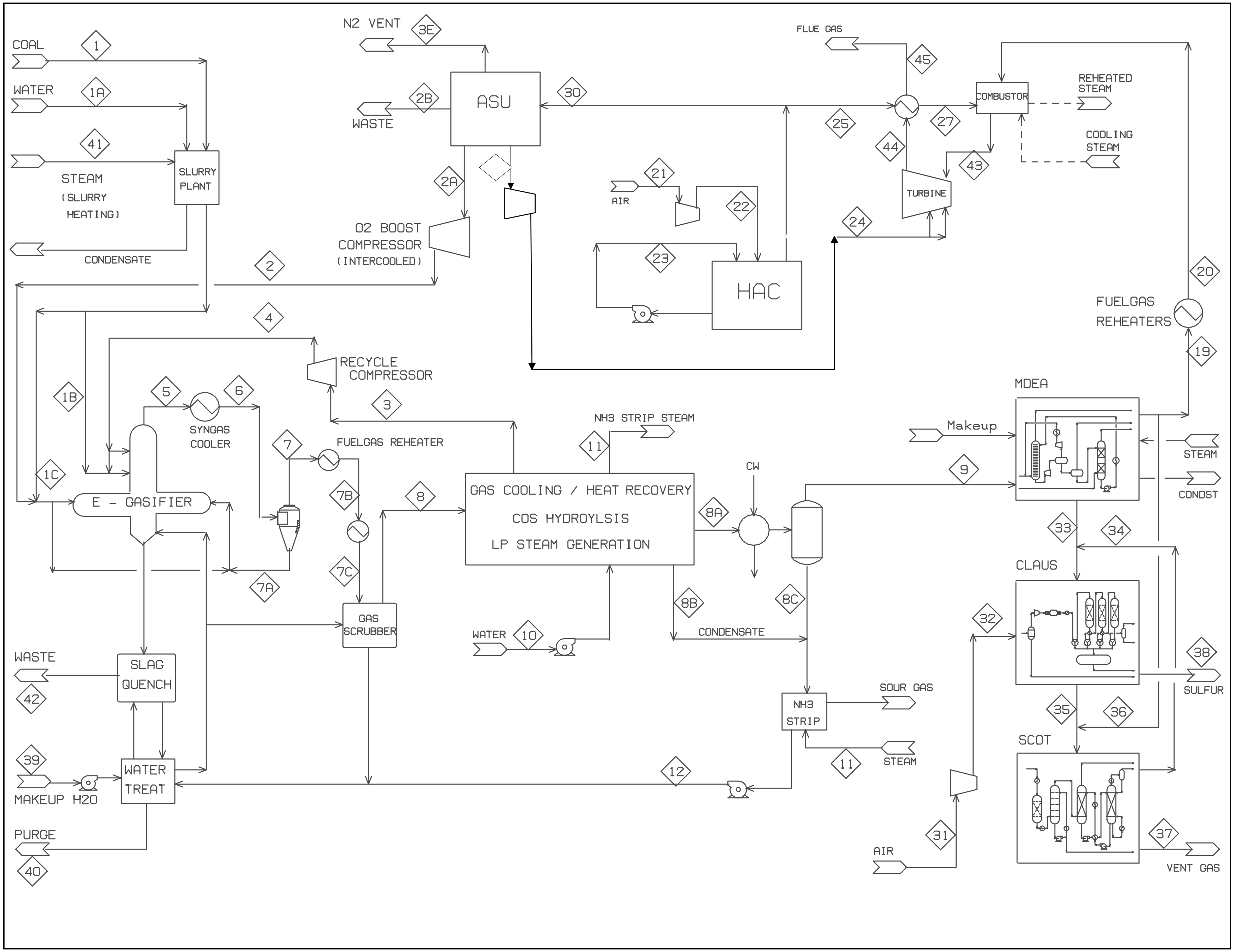
	MWe	EFFICIENCY	%
GT EXPANDER	498.8	LHV	43.8
HAC	170.7	HHV	39.6
CO2 RECOVERY	11.4		
MISC/AUX	16.5		
NET POWER	300.2		

STREAM ID	1	2	3	4	5	6	7	8	9	10
Mass Flow lb/hr	4203605	4203605	4196587	263544	3933043	3933043	3933043	108611	108611	4041657
Temperature F	59	66	60	100	100	275	725	60	191.6	2583
Pressure psi	14.7	15.3	282	277.9	277.9	273.8	277	150	350	268.5
H MMBtu/hr	-175.6	-168.5	-209.9	-10.1	-150.4	37.6	482.7	-218.5	-210.9	243.1

STREAM ID	13	14	15	16	17	18	19	20	21	22
Mass Flow lb/hr	4305211	4305211	4305211	80000	471902	471902	3901949	277066	270109	4305211
Temperature F	332.4	161.9	119.1	428	428	250.3	100	140	103.6	100
Pressure psi	14.9	14.8	14.7	35	35	45	14.7	25.7	3000	14.7
H MMBtu/hr	-2429.8	-2617.8	-2667.2	-449.3	-2650.1	-3136.9	-880.6	-1075.4	-1065.9	-2821.7

Hydraulic Air Compression (HAC)

- Destec (E-Gas^{TM}) / CGCU / "G" GT / No CO_2 Capture


COAL
WATER
STEAM
(SLURRY HEATING)
CONDENSATE
SLURRY PLANT
N2 VENT
WASTE
ASU
O2 BOOST COMPRESSOR (INTERCOOLED)
AIR
HAC
FLUE GAS
COMBUSTOR
REHEATED STEAM
COOLING STEAM
TURBINE
FUELGAS REHEATERS
RECYCLE COMPRESSOR
SYNGAS COOLER
FUELGAS REHEATER
E - GASIFIER
NH3 STRIP STEAM
GAS COOLING / HEAT RECOVERY
COS HYDROYLSIS
LP STEAM GENERATION
CW
MDEA
Makeup
STEAM
CONDST
GAS SCRUBBER
WATER
CONDENSATE
CLAUS
SULFUR
SLAG QUENCH
NH3 STRIP
SOUR GAS
SCOT
WATER TREAT
MAKEUP H2O
PURGE
AIR
VENT GAS

CASE 3

SUMMARY - COAL POWERED HAC PROCESS (NO CO2 CAPTURE)

	MWe			%
GT EXPANDER	499.1	EFFICIENCY		
STEAM TURBINE	30.9		LHV	43.8
HAC	184.1		HHV	42.3
MISC / AUX	20.0			
NET POWER	325.9			

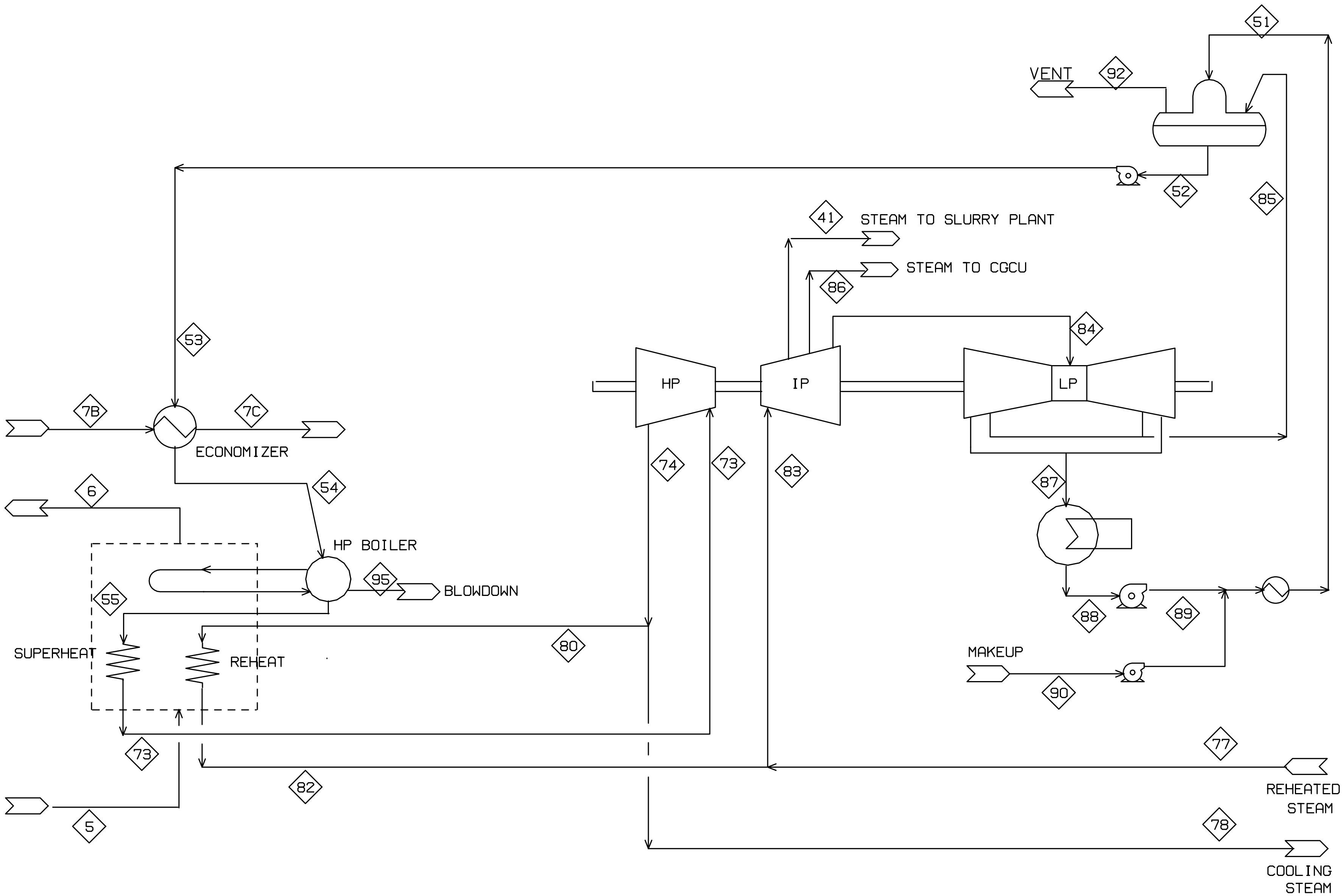
STREAM ID	1	1A	1B	1C	2A	2B	2	3E	3A	3	4	5	6	7
FLOW (lb/hr)	225480	75132	62883	237728	171462	865	171462	282097	263544	122547	122543	580965	580965	573350
TEMPERATURE ^{o}F	59	59	350	350	60	59	204.7	61.5	61.5	305.3	334.5	1900	1100	1100
PRESSURE psi	14.7	14.7	465	465	92	14.7	472	91	91	378	425	412	403.8	394.5
H (MMBtu/hr)	-705.9	-517	-132.6	-498.1	-0.8	-6	4.3	-3	-2.8	-322.9	-321.5	-1010.6	-1212	-1202.2

STREAM ID	7A	7B	7C	8	8A	8B	8C	9	10	11	12	19	20	21
FLOW (lb/hr)	7615	573350	573350	612734	409017	81170	9858	399159	45000	45000	90308	367192	367192	4537440
TEMPERATURE ^{o}F	1100	820	415	304.9	190	232.4	101.9	103	59	280	213.4	116	584.9	59
PRESSURE psi	394.5	390	390	380	354	354	20	349	14.7	37	470	340	330	14.7
H (MMBtu/hr)	-9.8	-1268.2	-1360.6	-1614.4	-847.5	-543.1	-63.5	-806.9	-309.7	-255.7	-606.3	-732.6	-666.6	-189.4

STREAM ID	22	23	24	25	27	30	31	32	33	34	35	36	37	38
FLOW (lb/hr)	4537440	5.06E+09	263544	3816000	3816000	718166	12185	12185	28014	1732	36482	6755	41505	5448
TEMPERATURE ^{o}F	65.8	59	100	60	1090	60	59	161.2	142.1	70	424	116	70	285
PRESSURE psi	15.3	58.6	105.7	282	14.7	275	14.7	25	18.5	17.5	26.7	340	17.5	14.7
H (MMBtu/hr)	-182	-3.46E+07	-0.3	-190.7	833	-15	-0.5	-0.2	-74.8	-6	-94.9	-13.5	-111.7	-0.6

STREAM ID	39	40	41	42	43	44	45		51	52	53	54	55	73
FLOW (lb/hr)	33516	75855	45945	29850	4183478	4447021	4447021		197294	199591	199591	199591	197595	197595
TEMPERATURE ^{o}F	59	200	821.6	200	2581.4	1141.2	268.5		205	217.3	222.5	620	629.3	1050
PRESSURE psi	14.7	15	150	15	268.5	15.2	14.7		17	16.3	2345.6	2011.1	1910.5	1800
H (MMBtu/hr)	-230.7	-507.7	-249.4	-99.4	141.1	-1586.3	-2611		-1320.5	-1333.4	-1331.3	-1241.7	-1130.6	-1058.1

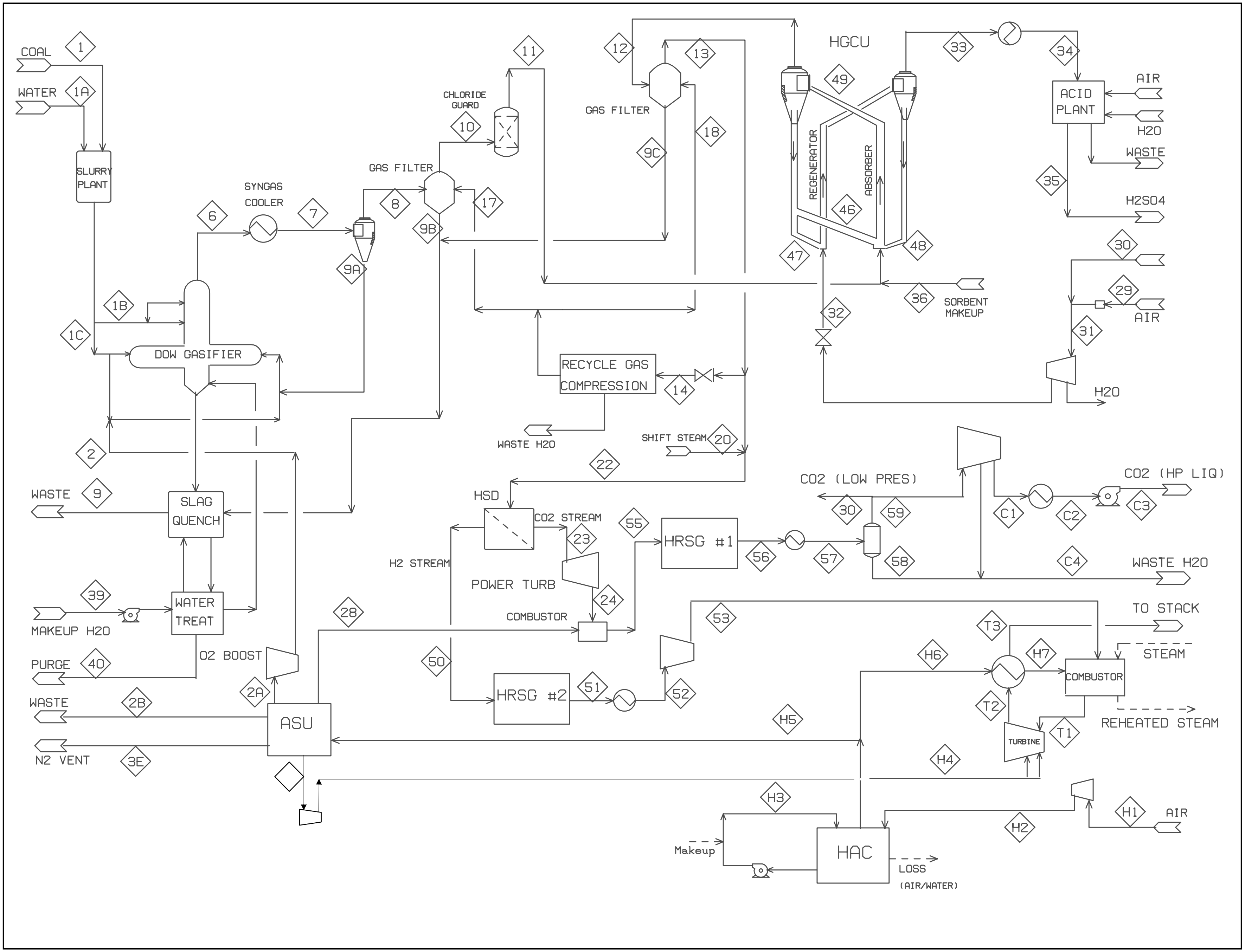
STREAM ID	74	77	78	80	82	83	84	85	86	87	88	89	90
FLOW (lb/hr)	197595	70000	70000	127595	127595	197595	98138	3300	53512	94838	94838	94838	102456
TEMPERATURE ^{o}F	606.7	606.7	1055.9	606.7	1050	1052.1	485.2	352.9	600.1	88.8	87.9	87.9	80
PRESSURE psi	350	350	342	350	342	342	35	17	60	0.7	0.7	40	14.7
H (MMBtu/hr)	-1096.9	-388.6	-371.8	-708.3	-678.1	-1049.9	-548.4	-18.6	-296.1	-554	-645.9	-645.8	-698.5



51
VENT
92
52
85
41
STEAM TO SLURRY PLANT
STEAM TO CGCU
86
84
53
HP
IP
LP
7B
7C
ECONOMIZER
74
73
83
87
54
6
HP BOILER
95
BLOWDOWN
55
88
89
80
SUPERHEAT
REHEAT
MAKEUP
90
73
77
82
REHEATED
STEAM
5
78
COOLING
STEAM

Hydraulic Air Compression (HAC)

- Destec High Pressure (E-Gas^{TM}) / HGCU / “G” GT / CO_2 Capture


COAL
WATER
SLURRY PLANT
DOW GASIFIER
SYNGAS COOLER
GAS FILTER
CHLORIDE GUARD
GAS FILTER
HGCU
REGENERATOR
ABSORBER
ACID PLANT
AIR
H2O
WASTE
H2SO4
AIR
SORBENT MAKEUP
RECYCLE GAS COMPRESSION
WASTE H2O
SHIFT STEAM
H2O
WASTE
SLAG QUENCH
WATER TREAT
MAKEUP H2O
PURGE
O2 BOOST
WASTE
N2 VENT
ASU
HSD
CO2 STREAM
H2 STREAM
POWER TURB
COMBUSTOR
HRSG #1
HRSG #2
CO2 (LOW PRES)
CO2 (HP LIQ)
WASTE H2O
TO STACK
STEAM
COMBUSTOR
REHEATED STEAM
TURBINE
AIR
HAC
Makeup
LOSS
(AIR/WATER)

CASE 4
HYDRAULIC AIR COMPRESSION CYCLE - COAL SYNGAS - CO2 SEQUESTRATION

	MWe
GT EXPANDER	501.7
CO2 EXPANDER	58.5
STEAM TURBINE	47.6
HAC	204.1
CO2 SEQ	28.2
H2 COMPR	26.1
MISC / AUX	36.9
NET POWER	312.4

EFFICIENCY	**%**
LHV	35.2
HHV	33.9

STREAM ID	1	1A	1B	1C	2A	2B	2	3E	6	7	8	9A	9B
ASPEN ID	COLIN	WAT1	COLB	COLA	GO2A	7	GOXYG	9	DRXROUT	RAWPRD	DRAWGAZ	FNES	16
Mass Flow lb/hr	269657	89852	75203	284306	179573	224	179573	574110	522761	522761	513654	9107	961
Temperature F	59	59	350	350	60	80.1	294.5	61.5	1904.8	1110	1110	1110	1098.2
Pressure psi	14.7	14.7	1078	1078	92	14.6	1150	91	1034	1024	1019	1019	14.7
H MMBtu/hr	-844.3	-618.7	-167.4	-626.7	-0.8	-1.5	7.8	-33.1	-831.9	-1016.9	-1005.2	-11.7	-1.2

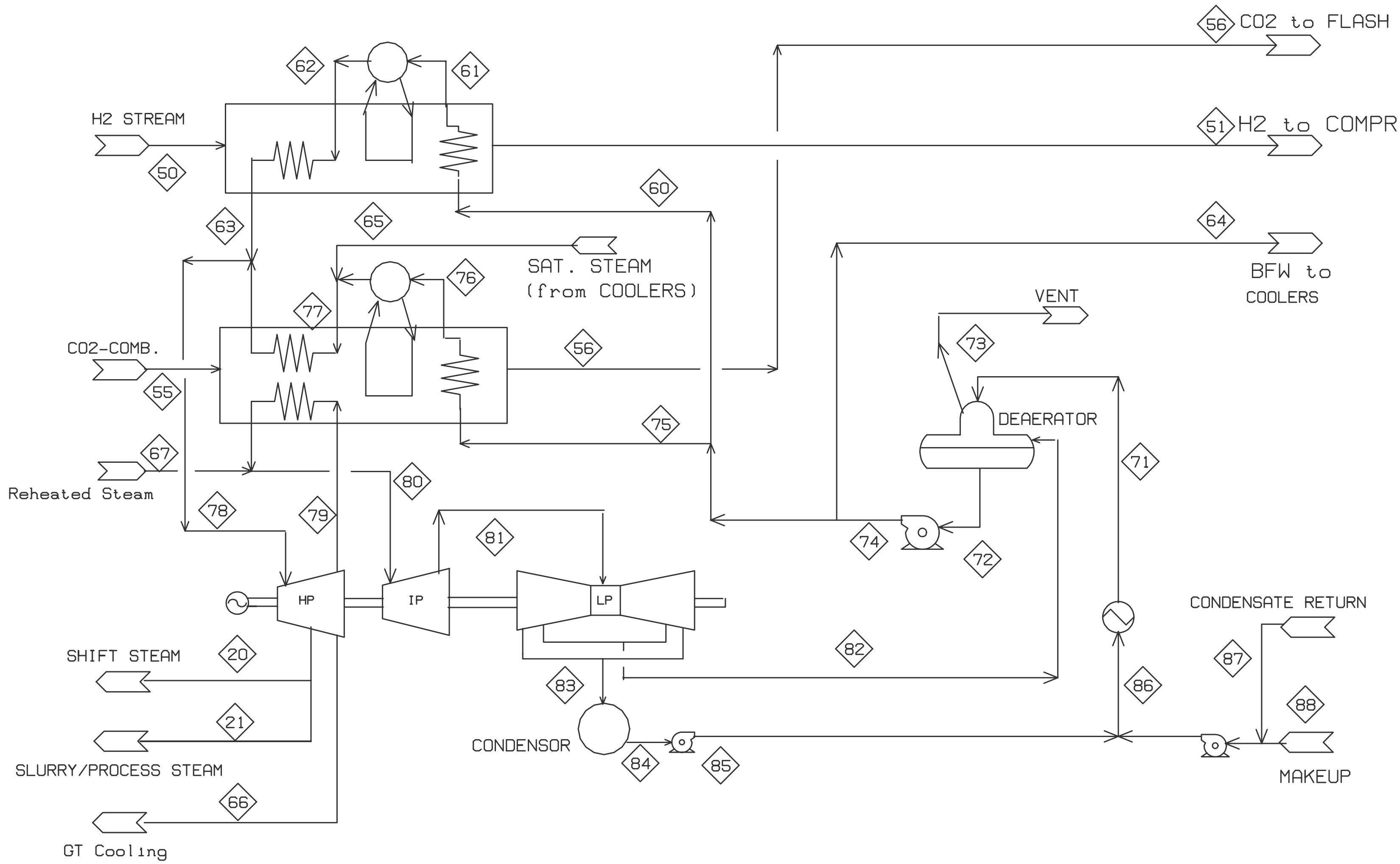
STREAM ID	9C	9	39	40	10	11	12	13	14	17	18	20	22
ASPEN ID	19	WSTSOL	MWATG	PURGE	17	18	20	26	21	25	24C	SHFSTM	TOSHF1
Mass Flow lb/hr	501	40588	32677	18983	520828	520037	517105	520991	12712	8135	4387	272791	781077
Temperature F	1129.3	200	59	200	1098.2	1094.3	1135.9	1129.3	1129.3	334.3	334.3	875	1013.5
Pressure psi	14.7	14.7	15	15	1000	985	975	965	965	1291.2	1291.2	1000	964
H MMBtu/hr	-1.9	-150.8	-225	-127.8	-1022.6	-1022.7	-1035.5	-1043.7	-25.5	-18.6	-10.1	-1482.8	-2501

STREAM ID	23	24	28	29	30	31	32	33	34	35	46	47	48
ASPEN ID	CO2RICH	S5	O2CAT	RAIR	30X	N830	39	5A	5	SACID	46	47	48
Mass Flow lb/hr	740345	740345	57449	42310	45526	87836	87145	90525	90525	20786	6440444	715605	712225
Temperature F	1391.2	555.3	60	59	60	56.7	260.9	1383.4	850	100	1134.6	1134.6	1383.4
Pressure psi	950	20.5	92	14.6	14.8	14.6	971	955	940	16	975	975	955
H MMBtu/hr	-2678.6	-2881.1	-0.3	-1.8	-174	-175.8	-168.2	-168.6	-181.7	-25.9	-22020.5	-2446.7	-2448.3

STREAM ID	49	50	51	52	53	55	56	57	58	59	C1	C2	C3
ASPEN ID	49	H2PRD	S10	S28	H2GT	CATOUT	S11	S35	N845	TOCO2CPF	CO2PROD	14	15
Mass Flow lb/hr	7673153	40727	40727	40727	40727	797793	797793	797793	152251	600015	593346	593346	593346
Temperature F	1135.9	1391.2	300	85	324.6	1868.9	275	80	80	80	268.3	85	103.6
Pressure psi	954	20.5	19.6	18.5	350	19.5	18.7	14.8	14.8	14.8	2100	2060	3000
H MMBtu/hr	-25500.7	175.2	28.6	0.2	32	-2881.4	-3297.1	-3504.2	-1044.1	-2286.6	-2245.8	-2310.7	-2307.4

STREAM ID	C4	H1	H2	H3	H4	H5	H6	H7	T1	T2	T3
ASPEN ID	C4	HVAIR	35	43	12	AIRASU	32	38	31	GTPCX	34
Mass Flow lb/hr	158920	5026390	5026390	5.61E+09	263554	1074908	3899243	3899243	3939979	4203533	4203533
Temperature F	80.9	59	66	59	100	60	60	1050	2585.2	1115.9	246
Pressure psi	14.8	14.7	15.3	58.6	120	282	282	282	268.5	15	15
H MMBtu/hr	-1089.5	-209.9	-201.4	-3.84E+07	-11.8	-53.8	-195	810.6	815.8	-934.1	-1939.7

HRSG/STEAM CYCLE



HYDRAULIC AIR COMPRESSION CYCLE - COAL SYNGAS - CO2 SEQUESTRATION

HRSG / STEAM CYCLE

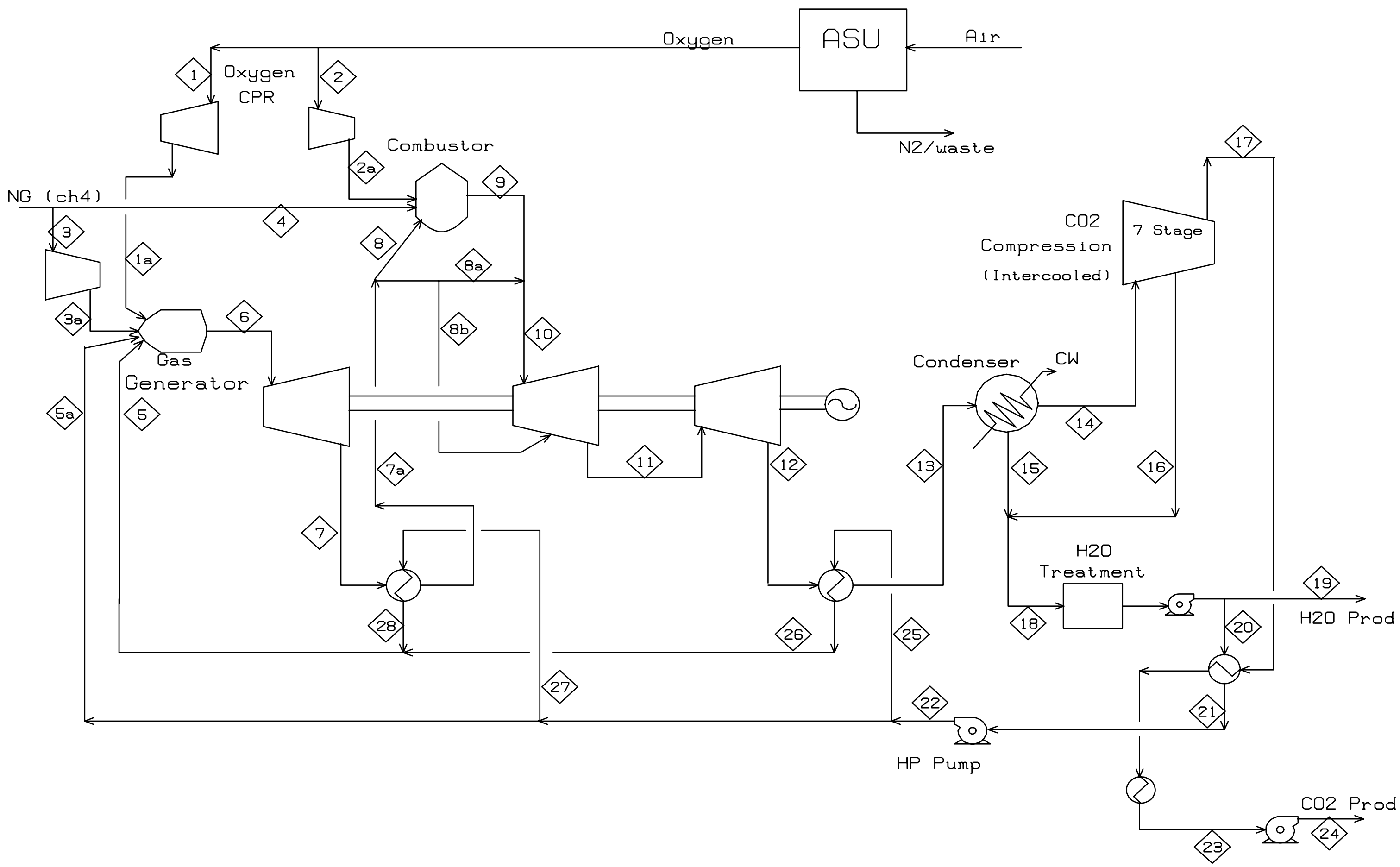
STREAM ID	20	21	60	61	62	63	64	65	66	67	71	72	73	74
ASPEN ID	SHFSTM	SLURSTM	TSTMCH4	S22	S23	S25	OSYNCO	RSYNCO	45	51	TODEAER	TOPMPHF	DVENT	S17
Mass Flow lb/hr	272791	79025	107747	107747	106670	106670	208156	208156	80000	80000	554276	560708	2818	560708
Temperature F	875	879.1	221.3	620	629.3	1050	221.3	635	709.8	1100.9	205	217.3	217.3	221.3
Pressure psi	1000	1000	2345.6	2011.1	1910.5	1800	2345.6	1911	518	492.1	17.1	16.3	16.3	2345.6
H MMBtu/hr	-1482.8	-429.1	-718.8	-670.3	-610.3	-571.2	-1388.7	-1188.5	-440.3	-423.3	-3709.8	-3745.9	-16.1	-3740.8

STREAM ID	75	76	77	78	79	80	81	82	83	84	85	86	87	88
ASPEN ID	TSTMCO2	TOBLR	S19	S20	44	IPTURIN	IPTUREX	LPDEAER	VLPEX	CNDOUT	TOMIX	TOCNDQ	SLURCND	MKUP
Mass Flow lb/hr	244805	244805	450513	557182	125367	205367	205367	9249	196117	196117	196117	554276	79025	279134
Temperature F	221.3	620	631.8	1050	709.8	1069.8	570.5	355	92.3	91	91	98.2	180	80
Pressure psi	2345.6	2011.1	1910.5	1800	518	492.1	63	17.1	0.8	0.7	20	20	20	20
H MMBtu/hr	-1633.2	-1523	-2575.1	-2983.8	-690.1	-1090.1	-1139.6	-52.2	-1145.8	-1335	-1335	-3769	-530.9	-1903.1

Rocket Engine (CES) - CO_2 Capture

Natural Gas CES (gas generator)

CES - Natural Gas - 400 MWe



CES - NETL System

Stream Results Summary 400 MWe - Natural Gas Case

Stream ID	1	1A	2	2A	3	3A	4	5	5A	6	7	7A	8
Temperature F	90.0	264.0	90.0	300.2	90.0	253.0	90.0	674.0	125.0	1850.5	1279.3	600.0	600.0
Pressure psi	30.0	2500.0	30.0	420.0	420.0	2500.0	420.0	2500.0	2600.0	2150.0	400.0	390.0	390.0
Mass Flow lb/hr	210594.0	210594.0	319668.0	319668.0	52000.0	52000.0	78933.0	864488.0	126976.0	1254060.0	1254060.0	1254060.0	1141194.0
Mass Flow lb/sec	58.5	58.5	88.8	88.8	14.4	14.4	21.9	240.1	35.3	348.3	348.3	348.3	317.0
Mole Flow lbmol/hr	6580.5	6580.5	9988.8	9988.8	3241.4	3241.4	4920.2	47985.8	7048.1	64855.8	64855.8	64855.8	59018.8
Enthalpy MMBtu/hr	0.6	7.3	0.8	15.5	-104.2	-100.6	-158.1	-4928.5	-859.3	-5881.1	-6257.6	-6685.5	-6083.8
Vapor Frac	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	0.000	1.000	1.000	1.000	1.000
Cp Btu/lb-R	0.220	0.260	0.220	0.232	0.581	0.734	0.581	1.863	1.004	0.590	0.524	0.489	0.489
Mass Flow lb/hr													
O2	209515.5	209515.5	318030.7	318030.7	0.0	0.0	0.0	0.0	0.0	2074.4	2074.4	2074.4	1887.7
N2	553.0	553.0	839.5	839.5	0.0	0.0	0.0	0.0	0.0	553.0	553.0	553.0	503.3
AR	525.8	525.8	798.1	798.1	0.0	0.0	0.0	0.0	0.0	525.8	525.8	525.8	478.4
H2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CO2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	142652.0	142652.0	142652.0	129813.3
H2O	0.0	0.0	0.0	0.0	0.0	0.0	0.0	864488.4	126975.7	1108260.0	1108260.0	1108260.0	1008510.0
CH4	0.0	0.0	0.0	0.0	52000.0	52000.0	78932.5	0.0	0.0	0.0	0.0	0.0	0.0
Mole Flow lbmol/hr													
O2	6547.6	6547.6	9938.8	9938.8	0.0	0.0	0.0	0.0	0.0	64.8	64.8	64.8	59.0
N2	19.7	19.7	30.0	30.0	0.0	0.0	0.0	0.0	0.0	19.7	19.7	19.7	18.0
AR	13.2	13.2	20.0	20.0	0.0	0.0	0.0	0.0	0.0	13.2	13.2	13.2	12.0
H2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CO2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3241.4	3241.4	3241.4	2949.7
H2O	0.0	0.0	0.0	0.0	0.0	0.0	0.0	47985.8	7048.1	61516.7	61516.7	61516.7	55980.2
CH4	0.0	0.0	0.0	0.0	3241.4	3241.4	4920.2	0.0	0.0	0.0	0.0	0.0	0.0
Mole Frac													
O2	0.995	0.995	0.995	0.995	0.000	0.000	0.000	0.000	0.000	0.001	0.001	0.001	0.001
N2	0.003	0.003	0.003	0.003	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
AR	0.002	0.002	0.002	0.002	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
H2	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
CO	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
CO2	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.050	0.050	0.050	0.050
H2O	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1.000	1.000	0.949	0.949	0.949	0.949
CH4	0.000	0.000	0.000	0.000	1.000	1.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000
total	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0

Stream Results Summary 400 MWe - Natural Gas Case

Stream ID	8A	8B	8C	9	10	11	12	13	14	15	16	17	18
Temperature F	600.0	600.0	600.0	2667.5	2600.0	1382.9	791.5	139.0	100.0	100.0	100.0	245.4	100.0
Pressure psi	390.0	390.0	390.0	380.0	380.0	18.1	2.1	2.0	1.9	1.9	5.7	2100.0	1.9
Mass Flow lb/hr	37622.0	60195.0	15049.0	1539797.0	1577419.0	1652662.0	1652662.0	1652662.0	519206.0	1133456.0	151077.0	368089.0	1284533.0
Mass Flow lb/sec	10.5	16.7	4.2	427.7	438.2	459.1	459.1	459.1	144.2	314.8	42.0	102.2	356.8
Mole Flow lbmol/hr	1945.7	3113.1	778.3	73927.8	75873.5	79764.8	79764.8	79764.8	16849.7	62915.1	8385.3	8463.2	71300.4
Enthalpy MMBtu/hr	-200.6	-320.9	-80.2	-6226.4	-6445.8	-7848.1	-8306.8	-8759.2	-2255.2	-7707.8	-1027.3	-1387.7	-8735.1
Vapor Frac	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	0.000	0.000	1.000	0.000
Cp Btu/lb-R	0.489	0.489	0.489	0.579	0.576	0.494	0.445	0.395	0.276	1.017	1.017	0.398	1.017
Mass Flow lb/hr													
O2	62.2	99.6	24.9	5036.5	5098.7	5223.2	5223.2	5223.2	5223.2	0.0	0.0	5197.1	0.0
N2	16.6	26.5	6.6	1342.7	1359.3	1392.5	1392.5	1392.5	1392.5	0.0	0.0	1385.5	0.0
AR	15.8	25.2	6.3	1276.5	1292.3	1323.8	1323.8	1323.8	1323.8	0.0	0.0	1317.2	0.0
H2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CO2	4279.6	6847.3	1711.8	346349.4	350629.0	359188.1	359188.1	359188.1	359172.9	15.2	21.4	359151.5	36.5
H2O	33247.6	53196.2	13299.1	1185790.0	1219040.0	1285540.0	1285540.0	1285540.0	152093.9	1133440.0	151055.9	1038.0	1284500.0
CH4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mole Flow lbmol/hr													
O2	1.9	3.1	0.8	157.4	159.3	163.2	163.2	163.2	163.2	0.0	0.0	162.4	0.0
N2	0.6	0.9	0.2	47.9	48.5	49.7	49.7	49.7	49.7	0.0	0.0	49.5	0.0
AR	0.4	0.6	0.2	32.0	32.3	33.1	33.1	33.1	33.1	0.0	0.0	33.0	0.0
H2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CO2	97.2	155.6	38.9	7869.9	7967.1	8161.6	8161.6	8161.6	8161.3	0.3	0.5	8160.8	0.8
H2O	1845.5	2952.8	738.2	65820.6	67666.2	71357.2	71357.2	71357.2	8442.4	62914.8	8384.8	57.6	71299.5
CH4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mole Frac													
O2	0.001	0.001	0.001	0.002	0.002	0.002	0.002	0.002	0.010	0.000	0.000	0.019	0.000
N2	0.000	0.000	0.000	0.001	0.001	0.001	0.001	0.001	0.003	0.000	0.000	0.006	0.000
AR	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.002	0.000	0.000	0.004	0.000
H2	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
CO	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
CO2	0.050	0.050	0.050	0.106	0.105	0.102	0.102	0.102	0.484	0.000	0.000	0.964	0.000
H2O	0.949	0.949	0.949	0.890	0.892	0.895	0.895	0.895	0.501	1.000	1.000	0.007	1.000
CH4	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
total	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0

Stream Results Summary 400 MWe - Natural Gas Case

Stream ID	19	20	21	21A	22	23	24	25	26	27	28
Temperature F	100.0	100.0	125.0	100.0	127.6	100.0	123	127.6	675.7	127.6	675.6
Pressure psi	50.0	50.0	47.5	1.9	2600.0	2060.0	3000	2600	2500	2600	2500
Mass Flow lb/hr	293033.0	991464.0	991464.0	1284497.0	991464.0	368089.0	368089	444258	444258	420230	420230
Mass Flow lb/sec	81.4	275.4	275.4	356.8	275.4	102.2	102.2	123.4	123.4	116.7	116.7
Mole Flow lbmol/hr	16265.6	55033.9	55033.9	71299.5	55033.9	8463.2	8463.2	24659.8	24659.8	23326.1	23326.1
Enthalpy MMBtu/hr	-1992.0	-6739.8	-6715.1	-8735.0	-6706.2	-1420.8	-1418.7	-3004.9	-2552.5	-2842.4	-2414.5
Vapor Frac	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1.000	0.000	1.000
Cp Btu/lb-R	0.996	0.996	0.997	1.017	0.988	0.706	0.578	0.988	2.905	0.988	2.913
Mass Flow lb/hr											
O2	0.0	0.0	0.0	0.0	0.0	5197.1	5197.1	0.0	0.0	0.0	0.0
N2	0.0	0.0	0.0	0.0	0.0	1385.5	1385.5	0.0	0.0	0.0	0.0
AR	0.0	0.0	0.0	0.0	0.0	1317.2	1317.2	0.0	0.0	0.0	0.0
H2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CO2	0.0	0.0	0.0	0.0	0.0	359151.5	359151.5	0.0	0.0	0.0	0.0
H2O	293032.7	991464.1	991464.1	1284500.0	991464.1	1038.0	1038.0	444257.9	444257.9	420230.5	420230.5
CH4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mole Flow lbmol/hr											
O2	0.0	0.0	0.0	0.0	0.0	162.4	162.4	0.0	0.0	0.0	0.0
N2	0.0	0.0	0.0	0.0	0.0	49.5	49.5	0.0	0.0	0.0	0.0
AR	0.0	0.0	0.0	0.0	0.0	33.0	33.0	0.0	0.0	0.0	0.0
H2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CO2	0.0	0.0	0.0	0.0	0.0	8160.8	8160.8	0.0	0.0	0.0	0.0
H2O	16265.6	55033.9	55033.9	71299.5	55033.9	57.6	57.6	24659.8	24659.8	23326.1	23326.1
CH4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mole Frac											
O2	0.000	0.000	0.000	0.000	0.000	0.019	0.019	0.000	0.000	0.000	0.000
N2	0.000	0.000	0.000	0.000	0.000	0.006	0.006	0.000	0.000	0.000	0.000
AR	0.000	0.000	0.000	0.000	0.000	0.004	0.004	0.000	0.000	0.000	0.000
H2	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
CO	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
CO2	0.000	0.000	0.000	0.000	0.000	0.964	0.964	0.000	0.000	0.000	0.000
H2O	1.000	1.000	1.000	1.000	1.000	0.007	0.007	1.000	1.000	1.000	1.000
CH4	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
total	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0

Natural Gas CES (gas generator)

POWER SUMMARY (CH4 FUEL)

	POWER kW	
CO2 Compression		
CO2 Compressor #1	13428.52	
CO2 Compressor #2	8573.21	
CO2 Compressor #3	8147.99	
total		30149.71
O2 Plant/Compressors		
Oxygen Plant	52933.98	
HP O2 Compressor	13721.52	
IP O2 Compressor	12513.97	
total		79169.47
Fuel Compressor		2425.37
Pumps/Fans		
Condensate Pump	63.58	
HP H2O Recycle Pump	2619.42	
HP CO2 Pump	610.15	
Water Pumps	8069.02	
Cooling Tower Fans	2570.15	
		13932.33
Turbine Power		
HP Turbine	-108696.35	
IP Turbine	-289003.18	
LP Turbine	-132418.05	
Total Turbines		-530117.58
(with CO2 Sequestration)		
Gross Power		-404440.70
Auxiliary (1.5%)		6066.61
Net Power		-398374.09
Efficiency		
% LHV		48.27
% HHV		43.63
(WITHOUT CO2 SEQUESTRATION)		
Gross Power		-421161.89
Auxiliary (1.5%)		6317.43
Net Power		-414844.47
Efficiency		
% LHV		50.26820776
% HHV		45.43182732

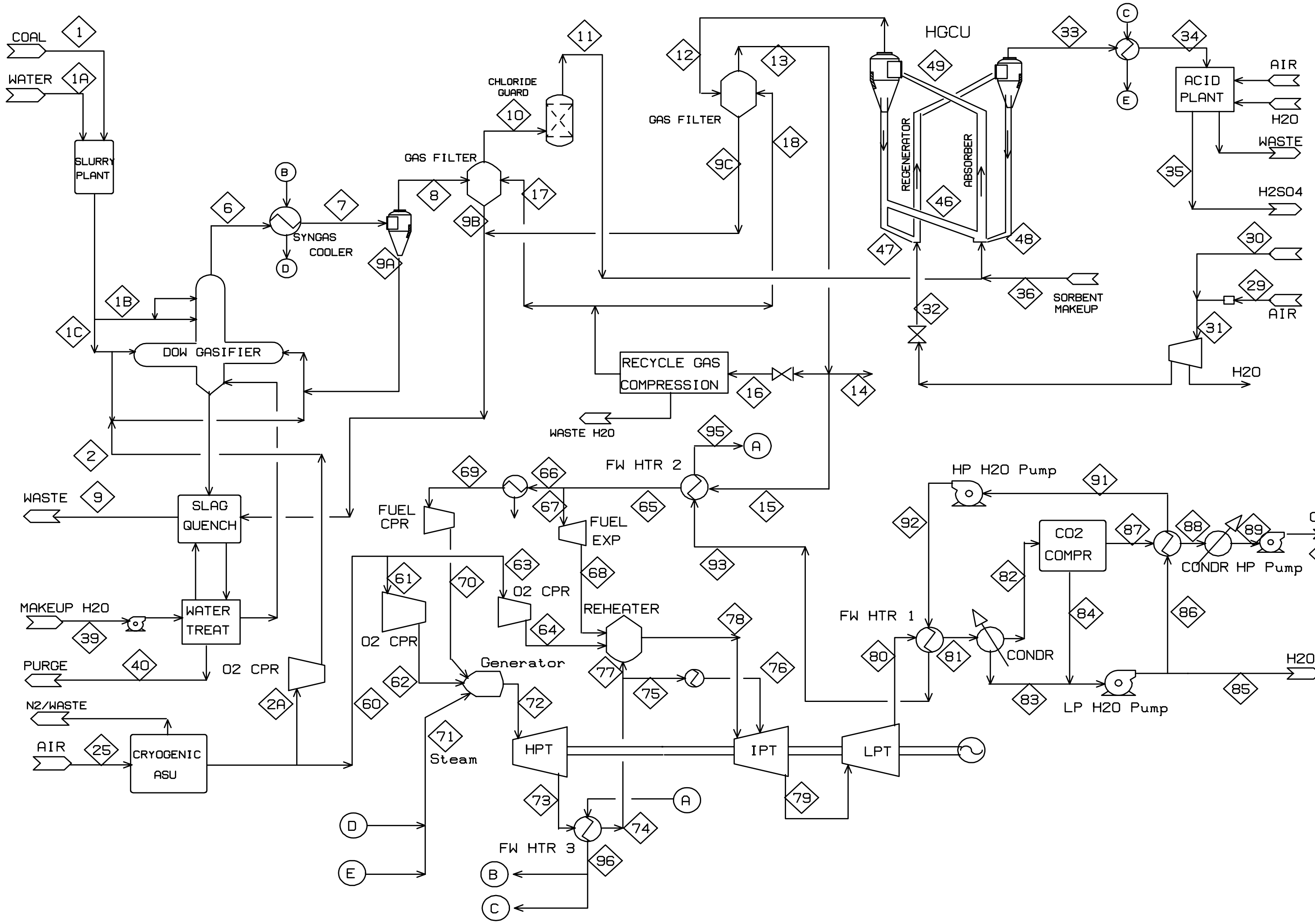
(with CO2 Sequestration)	
Gross Power	-404440.70
Auxiliary (1.5%)	6066.61
Net Power (KWe)	-398374.09
Efficiency	
% LHV	48.27
% HHV	43.63

(without CO2 SEQUESTRATION)	
Gross Power	-421161.89
Auxiliary (1.5%)	6317.43
Net Power	-414844.47
Efficiency	
% LHV	50.27
% HHV	45.43

Rocket Engine (CES) - CO_2 Capture

Coal Syngas CES (gas generator) – Destec HP / HGCU

Destec Gasification / CES Power Generation / CO2 Sequestration (406 MWe)



Destec Gasification - CES Power Generation
(mass/energy balances)

PFD STREAM #	1	1A	1B	1C	2A	2	6	7	8	9A	9B	9C	9	39	40
ASPEN NAME	COLIN	WAT1	COLB	COLA	GO2A	GOXYG	DRXROUT	RAWPRD	DRAWGAZ	FNES	16	19	WSTSOL	MWATG	PURGE
Temperature F	100	100	350	350	60	289.2	1905	1110	1110	1110	1099.4	1127.4	200	59	200
Pressure psi	14.7	14.7	1078	1078	18	1150	1034	1024	1019	1019	14.7	14.7	14.7	15	15
Mass Flow lb/hr	297507	99131	82970	313666	198509	198509	577138	577138	567090	10047	1061	553	44780	36051	20943
Mass Flow lb/sec	82.6	27.5	23	87.1	55.1	55.1	160.3	160.3	157.5	2.8	0.3	0.2	12.4	10	5.8
Mole Flow lbmol/hr		5502.5			6195.9	6195.9								2001.1	1162.5
Enthalpy MMBtu/hr	-920.2	-681.1	-185	-692.8	-0.8	8.6	-919.3	-1123.4	-1110.5	-12.9	-1.4	-2.1	-166.7	-249.4	-141.5

PFD STREAM #	11	12	13	14	15	16	17	18	25	29	30	33	34	35	46
ASPEN NAME	18	20	26	FUELASU	TOCES	21	25	24C	AIRTOT	RAIR	30X	5A	5	SACID	46
Temperature F	1095.5	1133.3	1127.4	1127.4	1127.4	1127.4	334.2	334.2	59	59	80	1382.7	850	100	1132.2
Pressure psi	985	975	965	964	964	965	1291.22	1291.22	14.7	14.55	14.8	955	940	16	975
Mass Flow lb/hr	573269	570035	573857	1511	559642	12712	8112	4375	2682809	46679	50228	99872	99872	22990	7105557
Mass Flow lb/sec	159.2	158.3	159.4	0.4	155.5	3.5	2.3	1.2	745.2	13	14	27.7	27.7	6.4	1973.8
Mole Flow lbmol/hr			30447.7	80.1	29693.5	674.5	430.1	231.9	92971.1	1617.6	1164.4	2623.4	2623.4	236.9	61072.5
Enthalpy MMBtu/hr	-1127.8	-1142.9	-1150.8	-3	-1122.3	-25.5	-18.5	-10	-112	-1.9	-191.3	-185.8	-200.2	-28.8	-24298.5

PFD STREAM #	48	49	60	61	62	63	64	65	66	67	68	69	70	71	72
ASPEN NAME	48	49	O260S	O2GEN	O2GENX	O2IPT	O2MEDX	50	FUELHPT	FUELIPT	41	HPFTCPR	FUELHPX	INJMIX	TOHP
Temperature F	1382.7	1133.3	60	60	284.8	60	277.8	680	680	680	518.6	205.4	202.8	798.2	1850
Pressure psi	955	954	18	18	2500	18	420	935	935	935	475	907	2500	2500	2150
Mass Flow lb/hr	785775	8465098	393061	128972	128972	264089	264089	559642	183638	376026	376026	171668	169030	1059534	1357535
Mass Flow lb/sec	218.3	2351.4	109.2	35.8	35.8	73.4	73.4	155.5	51	104.5	104.5	47.7	47	294.3	377.1
Mole Flow lbmol/hr	6553.6		12268.4	4025.5	4025.5	8242.9	8242.9	29693.5	9748.6	19961.8	19961.8	9084.2	8937.9	58812.4	67823.5
Enthalpy MMBtu/hr	-2701.3	-28139.3	-1.5	-0.5	5.1	-1	11.4	-1229	-403.3	-825.8	-850.9	-370.4	-355.9	-5896.6	-6256.7

PFD STREAM #	74	75	76	77	78	79	80	81	82	83	84	85	86	87	88
ASPEN NAME	25X	35	36	TORHT	RHT1EX	TOLP	TOHTREC	POC5	34	33	PINJWAT	H2OPROD	INJH2O	TOREF	37
Temperature F	680	680	620	680	2599.3	1416	828	143	100	100	100	100	100	244.9	158.8
Pressure psi	390	390	380	390	380	18.1	2.1	2	1.9	1.9	5.62	50	50	2100	2100
Mass Flow lb/hr	1357535	95027	95027	1262508	1934298	1997649	1997649	1997649	992970	1004679	290457	235451	1059534	702444	702444
Mass Flow lb/sec	377.1	26.4	26.4	350.7	537.3	554.9	554.9	554.9	275.8	279.1	80.7	65.4	294.3	195.1	195.1
Mole Flow lbmol/hr	67823.5	4747.6	4747.6	63075.8	84769.9	87935	87935	87935	32168.7	55766.3	16118.7	13069.4	58812.4	16048.2	16048.2
Enthalpy MMBtu/hr	-7052.9	-493.7	-496.4	-6559.2	-7583.4	-9034.2	-9552	-10088	-4331.7	-6832	-1974.6	-1600.6	-7202.5	-2664.8	-2696.4

PFD STREAM #	90	91	92	93	95	96
ASPEN NAME	CO2PROD	38	26X	53	40	11
Temperature F	122.5	130	133.3	602.8	663.8	674.8
Pressure psi	3000	25	2885	2797	2713	2577.3
Mass Flow lb/hr	702444	1059534	1059534	1059534	1059534	1059534
Mass Flow lb/sec	195.1	294.3	294.3	294.3	294.3	294.3
Mole Flow lbmol/hr	16048.2	58812.4	58812.4	58812.4	58812.4	58812.4
Enthalpy MMBtu/hr	-2724.2	-7171	-7159.9	-6623.9	-6517.1	-6115.4

CES Process Streams

	Fuel		Oxygen Streams					Fuel Streams					Steam - generator
PFD STREAM #	15	60	61	62	63	64	65	66	67	68	69	70	71
ASPEN NAME	TOCES	O260S	O2GEN	O2GENX	O2IPT	O2MEDX	50	FUELHPT	FUELIPT	41	HPFTCPR	FUELHPX	INJMIX
Temperature F	1127.4	60.0	60.0	284.8	60.0	277.8	680.0	680.0	680.0	518.6	205.4	202.8	798.2
Pressure psi	964.0	18.0	18.0	2500.0	18.0	420.0	935.0	935.0	935.0	475.0	907.0	2500.0	2500.0
Mass Flow lb/hr	559642	393061	128972	128972	264089	264089	559642	183638	376026	376026	171668	169030	1059534
Mass Flow lb/sec	155.5	109.2	35.8	35.8	73.4	73.4	155.5	51.0	104.5	104.5	47.7	47.0	294.3
Mole Flow lbmol/hr	29693.5	12268.4	4025.5	4025.5	8242.9	8242.9	29693.5	9748.6	19961.8	19961.8	9084.2	8937.9	58812.4
Enthalpy MMBtu/hr	-1122.3	-1.5	-0.5	5.1	-1.0	11.4	-1229.0	-403.3	-825.8	-850.9	-370.4	-355.9	-5896.6
Average MW	18.847	32.039	32.039	32.039	32.039	32.039	18.847	18.837	18.837	18.837	18.897	18.912	18.016
CPMX Btu/lb-R	0.435	0.219	0.219	0.258	0.219	0.231	0.417	0.417	0.417	0.409	0.406	0.430	0.831
Mole Frac													
O2	0.0000	0.9950	0.9950	0.9950	0.9950	0.9950	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N2	0.0036	0.0000	0.0000	0.0000	0.0000	0.0000	0.0036	0.0038	0.0038	0.0038	0.0041	0.0041	0.0000
AR	0.0010	0.0050	0.0050	0.0050	0.0050	0.0050	0.0010	0.0010	0.0010	0.0010	0.0011	0.0011	0.0000
H2	0.3803	0.0000	0.0000	0.0000	0.0000	0.0000	0.3803	0.3808	0.3808	0.3808	0.4086	0.4153	0.0000
CO	0.4295	0.0000	0.0000	0.0000	0.0000	0.0000	0.4295	0.4294	0.4294	0.4294	0.4608	0.4684	0.0000
CO2	0.0988	0.0000	0.0000	0.0000	0.0000	0.0000	0.0988	0.0986	0.0986	0.0986	0.1059	0.1076	0.0000
H2O	0.0840	0.0000	0.0000	0.0000	0.0000	0.0000	0.0840	0.0841	0.0841	0.0841	0.0172	0.0011	1.0000
CH4	0.0011	0.0000	0.0000	0.0000	0.0000	0.0000	0.0011	0.0009	0.0009	0.0009	0.0009	0.0009	0.0000
H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CL2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
HCL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NH3	0.0017	0.0000	0.0000	0.0000	0.0000	0.0000	0.0017	0.0014	0.0014	0.0014	0.0015	0.0015	0.0000
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NO2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Mass Frac													
O2	0.0000	0.9938	0.9938	0.9938	0.9938	0.9938	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N2	0.0053	0.0000	0.0000	0.0000	0.0000	0.0000	0.0053	0.0056	0.0056	0.0056	0.0060	0.0061	0.0000
AR	0.0022	0.0062	0.0062	0.0062	0.0062	0.0062	0.0022	0.0022	0.0022	0.0022	0.0024	0.0024	0.0000
H2	0.0407	0.0000	0.0000	0.0000	0.0000	0.0000	0.0407	0.0407	0.0407	0.0407	0.0436	0.0443	0.0000
CO	0.6384	0.0000	0.0000	0.0000	0.0000	0.0000	0.6384	0.6385	0.6385	0.6385	0.6830	0.6937	0.0000
CO2	0.2307	0.0000	0.0000	0.0000	0.0000	0.0000	0.2307	0.2305	0.2305	0.2305	0.2465	0.2504	0.0000
H2O	0.0802	0.0000	0.0000	0.0000	0.0000	0.0000	0.0802	0.0805	0.0805	0.0805	0.0164	0.0010	1.0000
CH4	0.0009	0.0000	0.0000	0.0000	0.0000	0.0000	0.0009	0.0007	0.0007	0.0007	0.0008	0.0008	0.0000
H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CL2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
HCL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NH3	0.0016	0.0000	0.0000	0.0000	0.0000	0.0000	0.0016	0.0012	0.0012	0.0012	0.0013	0.0013	0.0000
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NO2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

CES Process Streams

	To HP Turbine	From HP turbine	From FW Heater #3	Turbine cooling		Gas - Reheater	To IP Turbine	To LP Turbine	From LP Turbine	From FW Heater #1	To CO2 Compr	H2O - Condenser	H2O - CO2 CPR
PFD STREAM #	72	73	74	75	76	77	78	79	80	81	82	83	84
ASPEN NAME	TOHP	TOIP	25X	35	36	TORHT	RHT1EX	TOLP	TOHTREC	POC5	34	33	PINJWAT
Temperature F	1850.0	1283.1	680.0	680.0	620.0	680.0	2599.3	1416.0	828.0	143.0	100.0	100.0	100.0
Pressure psi	2150.0	400.0	390.0	390.0	380.0	390.0	380.0	18.1	2.1	2.0	1.9	1.9	5.6
Mass Flow lb/hr	1357535	1357535	1357535	95027	95027	1262508	1934298	1997649	1997649	1997649	992970	1004679	290457
Mass Flow lb/sec	377.1	377.1	377.1	26.4	26.4	350.7	537.3	554.9	554.9	554.9	275.8	279.1	80.7
Mole Flow lbmol/hr	67823.5	67823.5	67823.5	4747.6	4747.6	63075.8	84769.9	87935.0	87935.0	87935.0	32168.7	55766.3	16118.7
Enthalpy MMBtu/hr	-6256.7	-6651.2	-7052.9	-493.7	-496.4	-6559.2	-7583.4	-9034.2	-9552.0	-10088.0	-4331.7	-6832.0	-1974.6
Average MW	20.016	20.016	20.016	20.016	20.016	20.016	22.818	22.717	22.717	22.717	30.868	18.016	18.020
CPMX Btu/lb-R	0.573	0.510	0.475	0.475	0.474	0.475	0.534	0.464	0.418	0.365	0.276	1.017	1.016
Mole Frac													
O2	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0006	0.0006	0.0006	0.0006	0.0016	0.0000	0.0000
N2	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0013	0.0013	0.0013	0.0013	0.0035	0.0000	0.0000
AR	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0011	0.0010	0.0010	0.0010	0.0029	0.0000	0.0000
H2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0760	0.0760	0.0760	0.0760	0.0760	0.0760	0.1825	0.1787	0.1787	0.1787	0.4885	0.0000	0.0001
H2O	0.9225	0.9225	0.9225	0.9225	0.9225	0.9225	0.8140	0.8179	0.8179	0.8179	0.5024	1.0000	0.9998
CH4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CL2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
HCL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NH3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NO2	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0005	0.0005	0.0005	0.0005	0.0012	0.0000	0.0001
Mass Frac													
O2	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0008	0.0008	0.0008	0.0008	0.0016	0.0000	0.0000
N2	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0016	0.0016	0.0016	0.0016	0.0032	0.0000	0.0000
AR	0.0009	0.0009	0.0009	0.0009	0.0009	0.0009	0.0019	0.0018	0.0018	0.0018	0.0037	0.0000	0.0000
H2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.1671	0.1671	0.1671	0.1671	0.1671	0.1671	0.3520	0.3462	0.3462	0.3462	0.6964	0.0000	0.0002
H2O	0.8304	0.8304	0.8304	0.8304	0.8304	0.8304	0.6427	0.6487	0.6487	0.6487	0.2932	1.0000	0.9996
CH4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CL2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
HCL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NH3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NO2	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0009	0.0009	0.0009	0.0009	0.0019	0.0000	0.0002

CES Process Streams

	Excess H2O	Recycle H2O	From CO2 CPR	CO2 - Cooler	CO2 - Liquid	From CO2 Pump		Water to Steam Reheating for Gas Generator			
PFD STREAM #	85	86	87	88	89	90	91	92	93	95	96
ASPEN NAME	H2OPROD	INJH2O	TOREF	37	FRREF	CO2PROD	38	26X	53	40	11
Temperature F	100.0	100.0	244.9	158.8	100.0	122.5	130.0	133.3	602.8	663.8	674.8
Pressure psi	50.0	50.0	2100.0	2100.0	2060.0	3000.0	25.0	2885.0	2797.0	2713.0	2577.3
Mass Flow lb/hr	235451	1059534	702444	702444	702444	702444	1059534	1059534	1059534	1059534	1059534
Mass Flow lb/sec	65.4	294.3	195.1	195.1	195.1	195.1	294.3	294.3	294.3	294.3	294.3
Mole Flow lbmol/hr	13069.4	58812.4	16048.2	16048.2	16048.2	16048.2	58812.4	58812.4	58812.4	58812.4	58812.4
Enthalpy MMBtu/hr	-1600.6	-7202.5	-2664.8	-2696.4	-2728.1	-2724.2	-7171.0	-7159.9	-6623.9	-6517.1	-6115.4
Average MW	18.016	18.016	43.771	43.771	43.771	43.771	18.016	18.016	18.016	18.016	18.016
CPMX Btu/lb-R	0.996	0.996	0.401	0.730	0.693	0.572	0.997	0.987	1.389	2.303	
Mole Frac											
O2	0.0000	0.0000	0.0031	0.0031	0.0031	0.0031	0.0000	0.0000	0.0000	0.0000	0.0000
N2	0.0000	0.0000	0.0070	0.0070	0.0070	0.0070	0.0000	0.0000	0.0000	0.0000	0.0000
AR	0.0000	0.0000	0.0057	0.0057	0.0057	0.0057	0.0000	0.0000	0.0000	0.0000	0.0000
H2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0000	0.0000	0.9791	0.9791	0.9791	0.9791	0.0000	0.0000	0.0000	0.0000	0.0000
H2O	1.0000	1.0000	0.0027	0.0027	0.0027	0.0027	1.0000	1.0000	1.0000	1.0000	1.0000
CH4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CL2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
HCL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NH3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NO2	0.0000	0.0000	0.0024	0.0024	0.0024	0.0024	0.0000	0.0000	0.0000	0.0000	0.0000
Mass Frac											
O2	0.0000	0.0000	0.0023	0.0023	0.0023	0.0023	0.0000	0.0000	0.0000	0.0000	0.0000
N2	0.0000	0.0000	0.0045	0.0045	0.0045	0.0045	0.0000	0.0000	0.0000	0.0000	0.0000
AR	0.0000	0.0000	0.0052	0.0052	0.0052	0.0052	0.0000	0.0000	0.0000	0.0000	0.0000
H2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0000	0.0000	0.9844	0.9844	0.9844	0.9844	0.0000	0.0000	0.0000	0.0000	0.0000
H2O	1.0000	1.0000	0.0011	0.0011	0.0011	0.0011	1.0000	1.0000	1.0000	1.0000	1.0000
CH4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CL2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
HCL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NH3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NO2	0.0000	0.0000	0.0025	0.0025	0.0025	0.0025	0.0000	0.0000	0.0000	0.0000	0.0000

POWER SUMMARY

(ASPEN CONVENTION , "+" is power usage, "-" is power generation)

	POWER kW	
Air Separation Plant		
- Gasification	21835.9557	
- CES (generator+reheater)	43236.6613	
total		65072.617
Oxygen Compression		
- for gasifier	12071.374	
- for CES generator	9380.54256	
- for CES reheater	12066.522	
total		33518.43856
Syngas		
- HP Cpr for CES generator	4460.46151	
- Expander for CES reheater (credit)	-7256.7916	
total		-2796.33009
CO2 Compression		
- # 1 (1.9 to 17.85 psia)	25825.9715	
- # 2 (17.5 to 163.2 psia)	16320.2041	
- # 3 (160 to 2100 psia)	15416.7619	
total		57562.9375
Gasification Misc		
- HGCU/Recycle	5852.94348	
- pumps (slurry, makeup)	228.84847	
total		6081.79195
Cooling tower		
- pumps	6241.94946	
- fan	1978.63286	
total		8220.58232
CES pumps		
- condensate	65.5863712	
- HP water	3254.10419	
- CO2 pump	1146.33903	
total		4466.029591
Power Turbines		
- HP Turb	-113883.77	
- IP Turb	-323285.88	
- LP Turb	-149483.8	
total		-586653.45

GROSS POWER		-414527
Auxiliary POWER (2% of GROSS POWER)		8291
NET PLANT POWER		-406237
COAL USAGE (lbs/hr , dry)	264424	
- HHV (Btu/lb , dry)	13126.00	
- LHV (")	12656.94	
OVERALL EFFICIENCY		
- HHV basis %	39.96	
- LHV basis %	41.44	

Thermal Input		
- LHV (KW)	980316.6311	-0.414393496
- HHV (KW)	1016646.846	-0.399585005

CO2 as low pressure gas	(No sequestration - approximate)
Gross Power	-451520.98
Net Power	-442490.56
HHV %	43.52
LHV %	45.14

CO2 Compression

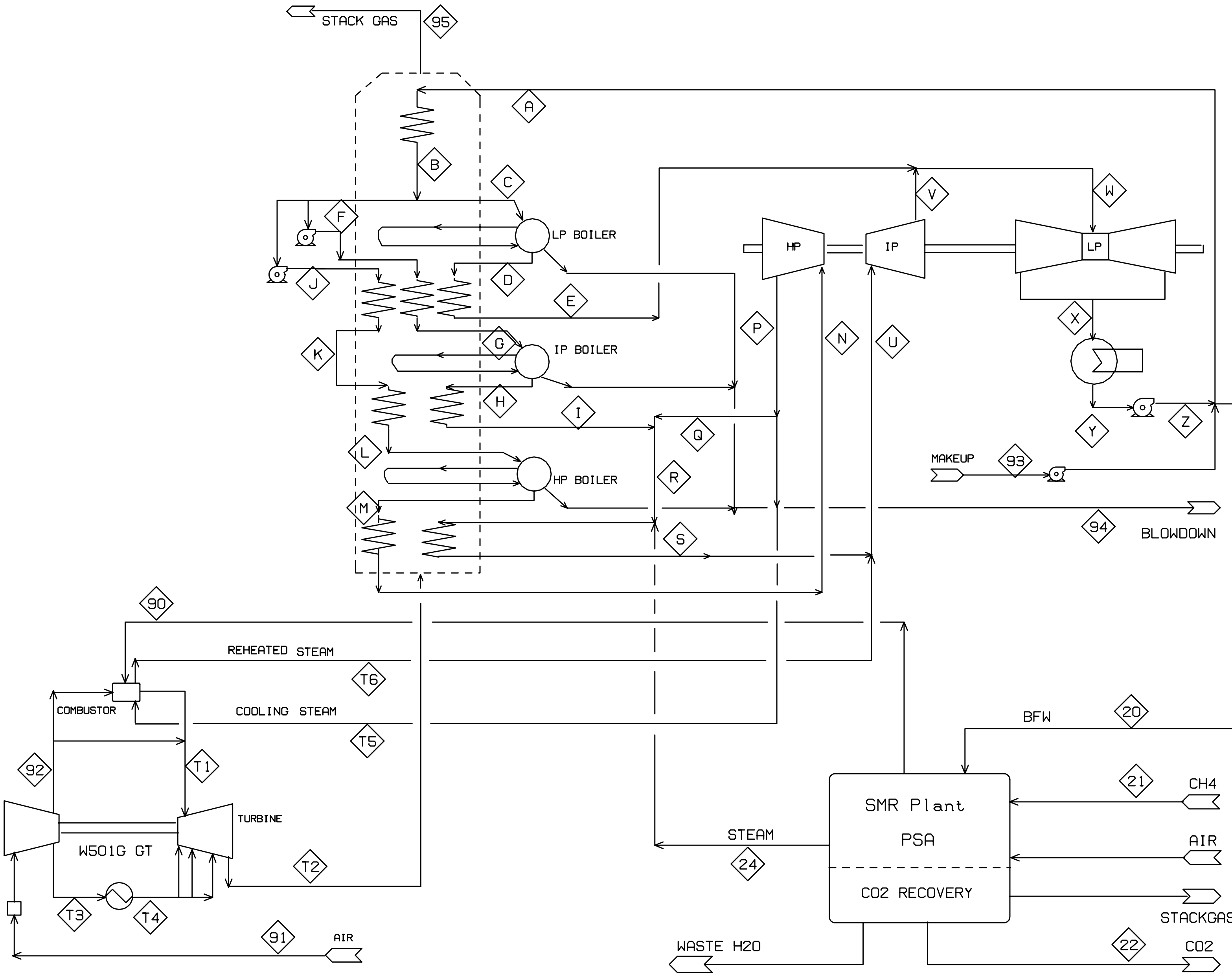
(ASPEN Representation was a series of three intercooled multistage compressors)

Compressor	# of Stages	Intercooling Temperature °F	Exit Cooling Temperature °F	Pressure Inlet (psia)	Pressure Outlet (psia)	Stage Isentropic Efficiency	Stage Mechanical Efficiency	Total Power (KWe)	Gas - Inlet (lbs/sec)	Liquid Prod (lbs/sec)	Total Cooling Duty (MMBtu/Hr)
1	2	100	100	1.9	17.85	0.85	0.985	25826	275.8	76.2	372
2	2	100	100	17.5	163.2	0.85	0.985	16320	199.6	4.1	73
3	3	100	n/a	160	2100	0.85	0.985	15417	195.5	0.0	56
							total: (KWe)	57563			

Hydrogen Turbine - CO_2 Capture

Hydrogen from Steam Methane Reforming (SMR)

Hydrogen from Steam Methane Reforming (SMR)



HYDROGEN TURBINE CYCLE - NATURAL GAS

	MWe	EFF:		
				(based on CH4)
GAS TURBINE	269.4			
STEAM TURBINE	174.8	LHV %	64.4	42.9
MISC/AUX	14.0			
SMR	3.6	HHV %	54.7	38.6
CO2 CPR	13.5			
NET POWER	413.1			

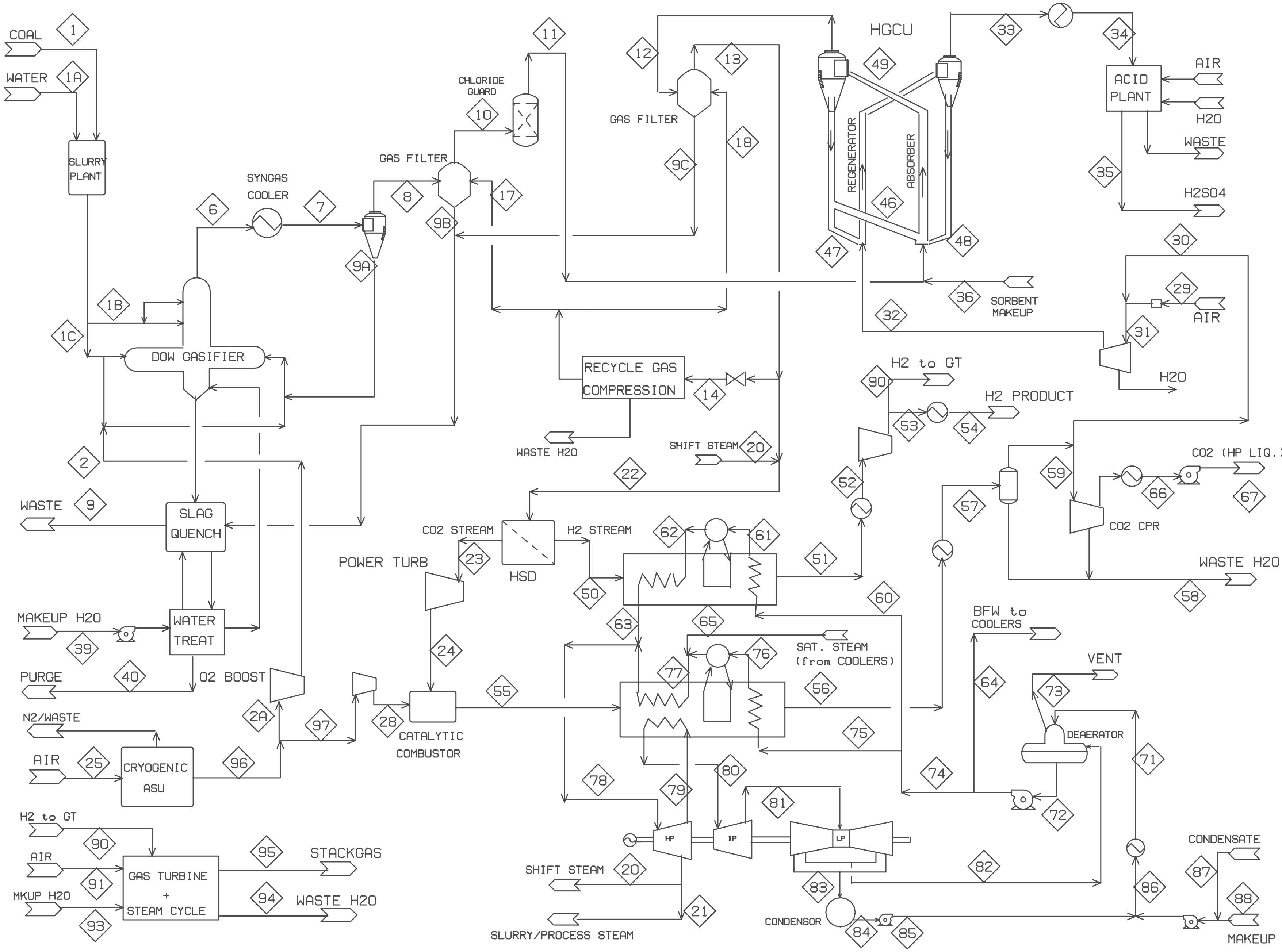
Stream PFD #	A	B	C	D	E	F	G	H	I	J	K	L	M	N	P
ASPEN Name ID	TOLPEC	HOTLP	TOLPEV	TOLPSH	LPTOIP	TOIPEC	TOIPEV	TOIPSH	FRIPSH	TOHPEC1	TOHPEC2	TOHPEV	TOHPSH	TOHPTUR	FRHPTUR
Temperature F	92	295	295	299.3	400	296.9	463	497.5	615	300.2	463	615	631.5	1050	759.9
Pressure psi	73.5	66.3	66.3	66.3	63	737	700	665	632	2263.8	2150.7	2043.1	1941	1800	632
Mass Flow lb/hr	667412	667412	143488	142054	142054	155514	155514	153959	153959	368410	368410	368410	364726	364726	364726
Mole Flow lbmol/hr	37047	37047	7965	7885	7885	8632	8632	8546	8546	20450	20450	20450	20245	20245	20245
Enthalpy MMBtu/hr	-4542.3	-4406.1	-947.3	-807.9	-800.3	-1026.2	-998.6	-872	-857.4	-2428.7	-2365.5	-2295.1	-2087.6	-1953.1	-1999.4

Stream PFD #	R	S	U	V	W	X	Y	Z	90	91	92	93	94	95	T1
ASPEN Name ID	TOREHT	40	TOIPTUR1	TOIPMX2	TOIPTUR2	TOCOND	TOCPMP	TOCMIX	FLH2	1	2	MAKUP	TBLOW	GTPC9	31
Temperature F	702.7	1050	1054.9	519.9	504.5	93.6	90	90.1	325	59	813.2	80	213	208.5	2583.1
Pressure psi	632	600	600	63	63	0.8	0.7	73.5	350	14.7	282.2	20	15	15	268.5
Mass Flow lb/hr	887785	887785	977785	977785	1119839	1119839	1119839	1119839	45203	4320000	3785688	29629	6674	4365208	3830896
Mole Flow lbmol/hr	49279	49279	54275	54275	62160	62160	62160	62160	21157	149707	131191	1645	370	160336	141820
Enthalpy MMBtu/hr	-4896.2	-4724.5	-5200.9	-5450.1	-6250.3	-6560.5	-7623.8	-7623.5	35.8	-180.4	551	-202	-42.2	-2201.7	547.9

Stream PFD #	T3	T4	T5	T6	20	21	22	24
ASPEN Name ID	3	12	C3	C4	TOREFORM	CH4R	CO2CAL	32
Temperature F	813.2	600	759.9	1103.2	89.8	60	123	700
Pressure psi	282.2	277	632	600	73.5	150	3000	632
Mass Flow lb/hr	527109	527109	90000	90000	482056	152843	297040	459101
Mole Flow lbmol/hr	18267	18267	4996	4996	26758	9527	6749	25484
Enthalpy MMBtu/hr	76.7	47.9	-493.4	-476.3	-3281.8	-307.4	-1168.2	-2532.7

Hydrogen Turbine - CO_2 Capture

Destec High Pressure (E-Gas^{TM}) / HGCU / HSD


COAL
WATER
SLURRY PLANT
DOW GASIFIER
SYNGAS COOLER
GAS FILTER
CHLORIDE GUARD
GAS FILTER
HGCU
REGENERATOR
ABSORBER
ACID PLANT
AIR
H2O
WASTE
H2SO4
SORBENT MAKEUP
AIR
H2O
RECYCLE GAS COMPRESSION
WASTE H2O
SHIFT STEAM
H2 to GT
H2 PRODUCT
CO2 (HP LIQ.)
CO2 CPR
WASTE H2O
WASTE
SLAG QUENCH
MAKEUP H2O
WATER TREAT
PURGE
O2 BOOST
N2/WASTE
AIR
CRYOGENIC ASU
CO2 STREAM
H2 STREAM
HSD
POWER TURB
CATALYTIC COMBUSTOR
SAT. STEAM (from COOLERS)
BFW to COOLERS
VENT
DEAERATOR
H2 to GT
AIR
MKUP H2O
GAS TURBINE + STEAM CYCLE
STACKGAS
WASTE H2O
SHIFT STEAM
SLURRY/PROCESS STEAM
HP
IP
LP
CONDENSOR
CONDENSATE
MAKEUP

HYDROGEN TURBINE CYCLE - COAL

	MWe		MWe		
GAS TURBINE	269.5	MISC	-54.2	EFFICIENCY:	
STEAM TURBINE	167.2	GROSS WORK	386.9	LHV %	38.0
EXPANDER	65.0	AUX (3%)	-11.6	HHV %	36.6
CO2 SEQ.	-31.6	NET POWER	375.3		
H2 CPR	-29.1				

Stream PFD #	1	1A	1B	1C	2A	2	6	7	8	9A	9B	9C	9	39	40	10
ASPEN Name ID	COLIN	WAT1	COLB	COLA	GO2A	GOXYG	DRXROUT	RAWPRD	DRAWGAZ	FNES	16	19	WSTSOL	MWATG	PURGE	17
Temperature F	59	59	350	350	60	289.4	1905	1110	1110	1110	1099.4	1130.8	200	59	200	1099.4
Pressure psi	14.7	14.7	1078	1078	18	1150	1034	1024	1019	1019	14.7	14.7	14.7	15	15	1000
Mass Flow lb/hr	299868	99918	83629	316157	199814	199814	581450	581450	571323	10127	1069	557	45135	36338	21109	578388
Mole Flow lbmol/hr		5546			6237	6237								2017	1172	
Enthalpy MMBtu/hr	-938.8	-688	-186.1	-696.9	-0.8	8.5	-925.3	-1131.1	-1118.1	-13	-1.4	-2.1	-167.7	-250.2	-142.1	-1135.4

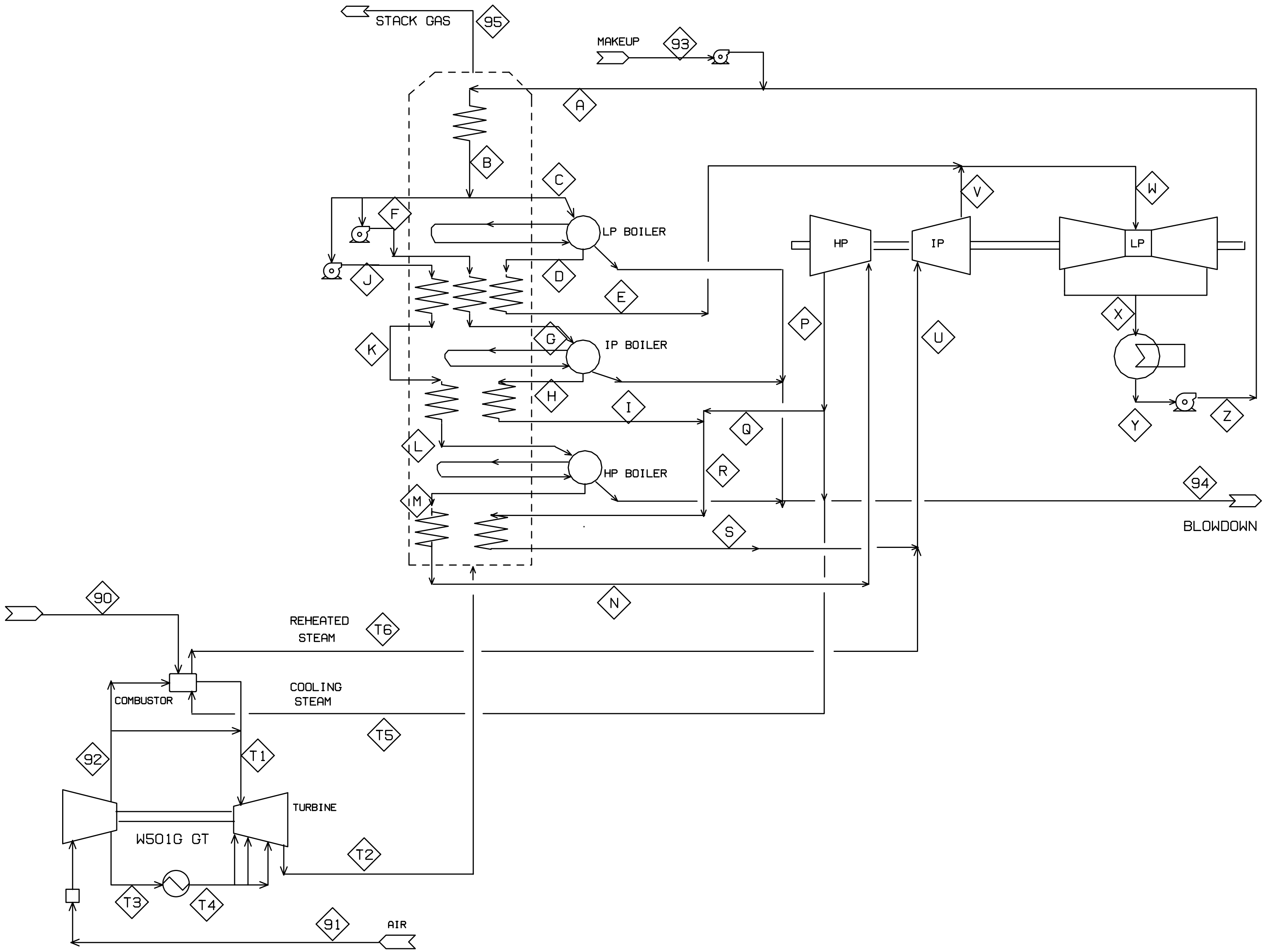
Stream PFD #	11	12	13	14	17	18	20	21	22	23	24	25	96	97	28	29
ASPEN Name ID	18	20	26	21	25	24C	SHFSTM	SLURSTM	TOSHF1	CO2RICH	S5	AIRASU	10	O2CAT	N862	RAIR
Temperature F	1095.4	1136.6	1130.8	1130.8	334.3	334.3	875	879.1	1014.4	1391.9	555.6	59	60	80	159.1	59
Pressure psi	985	975	965	965	1291.2	1291.2	1000	1000	964	950	20.5	14.6	18	16.5	25	14.6
Mass Flow lb/hr	577509	574248	578078	12712	8135	4387	303352	87912	868726	823336	823336	1193496	263168	63356	63356	47049
Mole Flow lbmol/hr			30687	675	432	233	16838	4880	46851	25690	25690	41360	8214	1977	1977	1630
Enthalpy MMBtu/hr	-1135.5	-1149.9	-1157.8	-25.5	-18.6	-10.1	-1648.9	-477.4	-2781.2	-2979	-3204.3	-49.8	-1	0	1.1	-2

Stream PFD #	30	31	32	33	34	35	46	47	48	49	50	51	52	53	54	55
ASPEN Name ID	30X	N830	39	5A	5	SACID	46	47	48	49	H2PRD	S10	S28	S34	H2HPPRD	CATOUT
Temperature F	60	56.7	260.9	1385.5	850	100	1135.5	1135.5	1385.5	1136.6	1391.9	300	85	324.6	190	1870.2
Pressure psi	14.8	14.6	971	955	940	16	975	975	955	954	20.5	19.6	18.5	350	346.5	19.5
Mass Flow lb/hr	50627	97676	96917	100678	100678	23173	7161983	795776	792015	8532007	45385	45385	45385	1	1	886692
Mole Flow lbmol/hr	1174	2804	2762	2645	2645	239	61558	6840	6606		21161	21161	21161	0	0	26022
Enthalpy MMBtu/hr	-193.3	-195.3	-186.9	-187.3	-201.9	-28.9	-24486.1	-2720.7	-2722.3	-28354.7	195	31.8	0.2	0	0	-3203.1

Stream PFD #	56	57	58	59	60	61	62	63	64	65	66	67	71	72	73	74
ASPEN Name ID	S11	S35	N845	TOCO2CPF	TSTMCH4	S22	S23	S25	TOSYNCOI	FRSYNCOL	14	CO2LIQ	TODEAER	TOPMPHP	DVENT	S17
Temperature F	275	80	80	80	221.3	620	629.3	1050	221.3	635	100	123	205	217.3	217.3	221.3
Pressure psi	18.7	14.8	14.8	14.8	2345.6	2011.1	1910.5	1800	2345.6	1911	2060	3000	17.1	16.3	16.3	2345.6
Mass Flow lb/hr	886692	886691	169126	666937	120018	120018	118818	118818	231609	231609	659527	659527	604672	611688	3074	611688
Mole Flow lbmol/hr	26022	26022	9384	15465	6662	6662	6595	6595	12856	12856	15054	15054	33564	33953	171	33953
Enthalpy MMBtu/hr	-3665.6	-3895.7	-1159.9	-2542.8	-800.7	-746.7	-679.8	-636.3	-1545.2	-1322.4	-2562.7	-2558.4	-4047.1	-4086.5	-17.6	-4080.9

Stream PFD #	75	76	77	78	79	80	81	82	83	84	85	86	87	88	90	91
ASPEN Name ID	TSTMCO2	TOBLR	S19	S20	HPTUREX	IPTURIN	IPTUREX	LPDEAER	VLPEX	CNDOUT	TOMIX	TOCNDQ	SLURCND	MKUP	90	1
Temperature F	221.3	620	631.9	1050	709.8	1050	555.8	355	92.3	91	91	98.3	180	80	324.6	59
Pressure psi	2345.6	2011.1	1910.5	1800	518	492.1	63	17.1	0.8	0.7	20	20	20	20	350	14.7
Mass Flow lb/hr	260062	260062	489070	607887	216623	216623	216623	10090	206533	206533	206533	604672	87912	310227	45384	4320000
Mole Flow lbmol/hr	14435	14435	27147	33742	12024	12024	12024	560	11464	11464	11464	33564	4880	17220	21161	149707
Enthalpy MMBtu/hr	-1735	-1618	-2795.5	-3255.3	-1192.4	-1152.2	-1203.6	-57	-1207.5	-1405.9	-1405.8	-4111.5	-590.6	-2115.1	35.6	-180.4

Stream PFD #	93	94	95	96	97
ASPEN Name ID	MAKUP	TBLOW	GTPC9	10	O2CAT
Temperature F	80	213	208.5	60	80
Pressure psi	20	15	15	18	16.5
Mass Flow lb/hr	7046	7046	4365389	263168	63356
Mole Flow lbmol/hr	391	391	160341	8214	1977
Enthalpy MMBtu/hr	-48	-44.4	-2201.9	-1	0


STACK GAS
95
MAKEUP
93
A
B
C
F
LP BOILER
J
D
E
K
G
IP BOILER
H
I
L
HP BOILER
M
N
S
P
Q
R
U
V
W
HP
IP
LP
X
Y
Z
94
BLOWDOWN
90
REHEATED
STEAM
T6
COMBUSTOR
COOLING
STEAM
T5
92
T1
TURBINE
W501G GT
T2
T3
T4
91
AIR

HYDROGEN TURBINE CYCLE - COAL

STEAM CYCLE

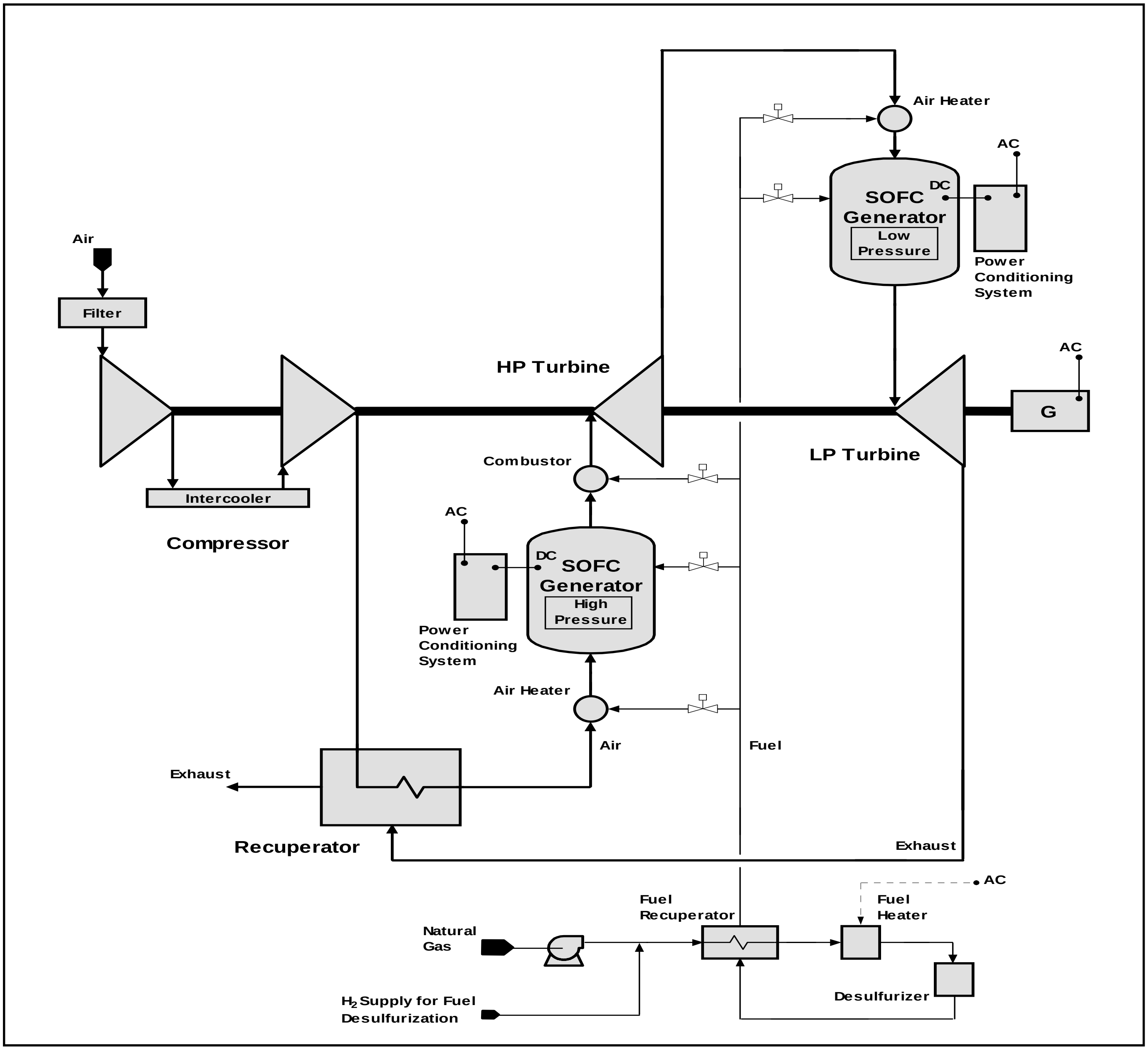
Stream PFD #	A	B	C	D	E	F	G	H	I	J	K	L	M	N	P	Q
ASPEN Name ID	TOLPEC	HOTLP	TOLPEV	TOLPSH	LPTOIP	TOIPEC	TOIPEV	TOIPSH	FRIPSH	TOHPEC1	TOHPEC2	TOHPEV	TOHPSH	TOHPTUR	FRHPTUR	TMXIP
Temperature F	92	295	295	299.3	400	296.4	463	472.8	615	300	463	615	631.5	1050	712	712
Pressure psi	73.5	66.3	66.3	66.3	63	585.7	556.4	528.6	518	2263.8	2150.7	2043.1	1941	1800	518	518
Mass Flow lb/hr	703403	703403	89167	88276	88276	170988	170988	169278	169278	443247	443247	443247	438814	438814	438814	358814
Mole Flow lbmol/hr	39044	39044	4949	4900	4900	9491	9491	9396	9396	24604	24604	24604	24358	24358	24358	19917
Enthalpy MMBtu/hr	-4787.2	-4643.7	-588.7	-502	-497.3	-1128.4	-1098	-958.5	-941.1	-2922.1	-2846	-2761.3	-2511.7	-2349.9	-2414.8	-1974.6

Stream PFD #	R	S	U	V	W	X	Y	Z	90	91	92	93	94	95	T1	T2
ASPEN Name ID	TOREHT	40	TOIPTUR1	TOIPMX2	TOIPTUR2	TOCOND	TOCPMP	TOCMIX	90	1	2	MAKUP	TBLOW	GTPC9	31	33
Temperature F	680.1	1050	1057	561	540.4	93.6	90	90.1	324.6	59	813.2	80	213	208.5	2583.1	1088.4
Pressure psi	518	492	492	63	63	0.8	0.7	73.5	350	14.7	282.2	20	15	15	268.5	15
Mass Flow lb/hr	528093	528093	608093	608093	696369	696369	696369	696369	45384	4320000	3785688	7034	7034	4365389	3831077	4365389
Mole Flow lbmol/hr	29313	29313	33754	33754	38654	38654	38654	38654	21161	149707	131191	390	390	160341	141825	160341
Enthalpy MMBtu/hr	-2915.7	-2808.8	-3232	-3377.1	-3874.4	-4072.2	-4740.9	-4740.7	35.6	-180.4	551	-48	-44.3	-2201.9	547.7	-1145

Stream PFD #	T3	T4	T5	T6
ASPEN Name ID	3	12	C3	C4
Temperature F	813.2	600	712	1103.2
Pressure psi	282.2	277	518	492
Mass Flow lb/hr	527109	527109	80000	80000
Mole Flow lbmol/hr	18267	18267	4441	4441
Enthalpy MMBtu/hr	76.7	47.9	-440.2	-423.2

Hybrid Cycles (Turbine / SOFC)

Natural Gas Hybrid Turbine / SOFC


Air Heater
AC
SOFC
Generator
Low
Pressure
DC
Power
Conditioning
System
Air
Filter
HP Turbine
AC
G
LP Turbine
Combustor
Intercooler
Compressor
AC
DC
SOFC
Generator
High
Pressure
Power
Conditioning
System
Air Heater
Air
Fuel
Exhaust
Recuperator
Exhaust
AC
Fuel
Recuperator
Fuel
Heater
Natural
Gas
Desulfurizer
H2 Supply for Fuel
Desulfurization

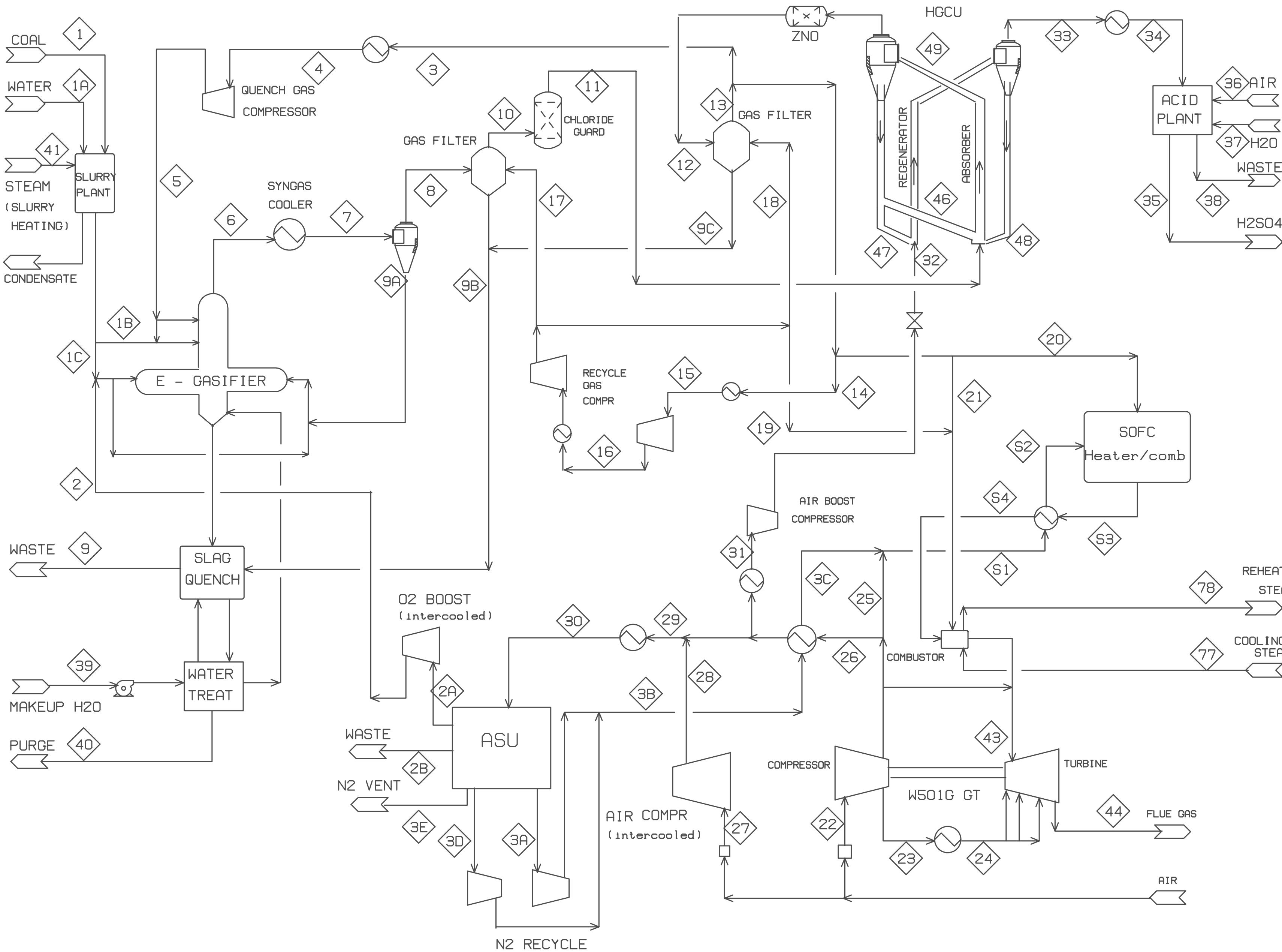
Natural Gas Hybrid M&E

See report:

"Pressurized Solid Oxide Fuel Cycle/Gas Turbine Power System" by Siemens Westinghouse / Rolls-Royce Allison for the DOE. (DE-AC26-98FT40355 , February 2000).

Hybrid Cycles (Turbine / SOFC)

Destec (E-Gas^{TM}) / HGCU / "G" GT / No CO_2 Capture



GASIFICATION - HYBRID (NO CO2 CAPTURE)

E-GAS (DESTEC) GASIFICATION - HYBRID POWER SYSTEM

4/29/2002

(GAS TURBINE / HGCU/SOFC/STEAM CYCLE)

(NO CO2 SEQUESTRATION)

(58% syngas to SOFC)

	POWER kW		
GAS TURBINE	-276.1	LHV EFFICIENCY	56.4 %
SOFC	-221.4		
STEAM TURBINE	-207.7	HHV EFFICIENCY	54.4 %
MISC	41.6		
AUX	19.9		
NET POWER	-643.6		

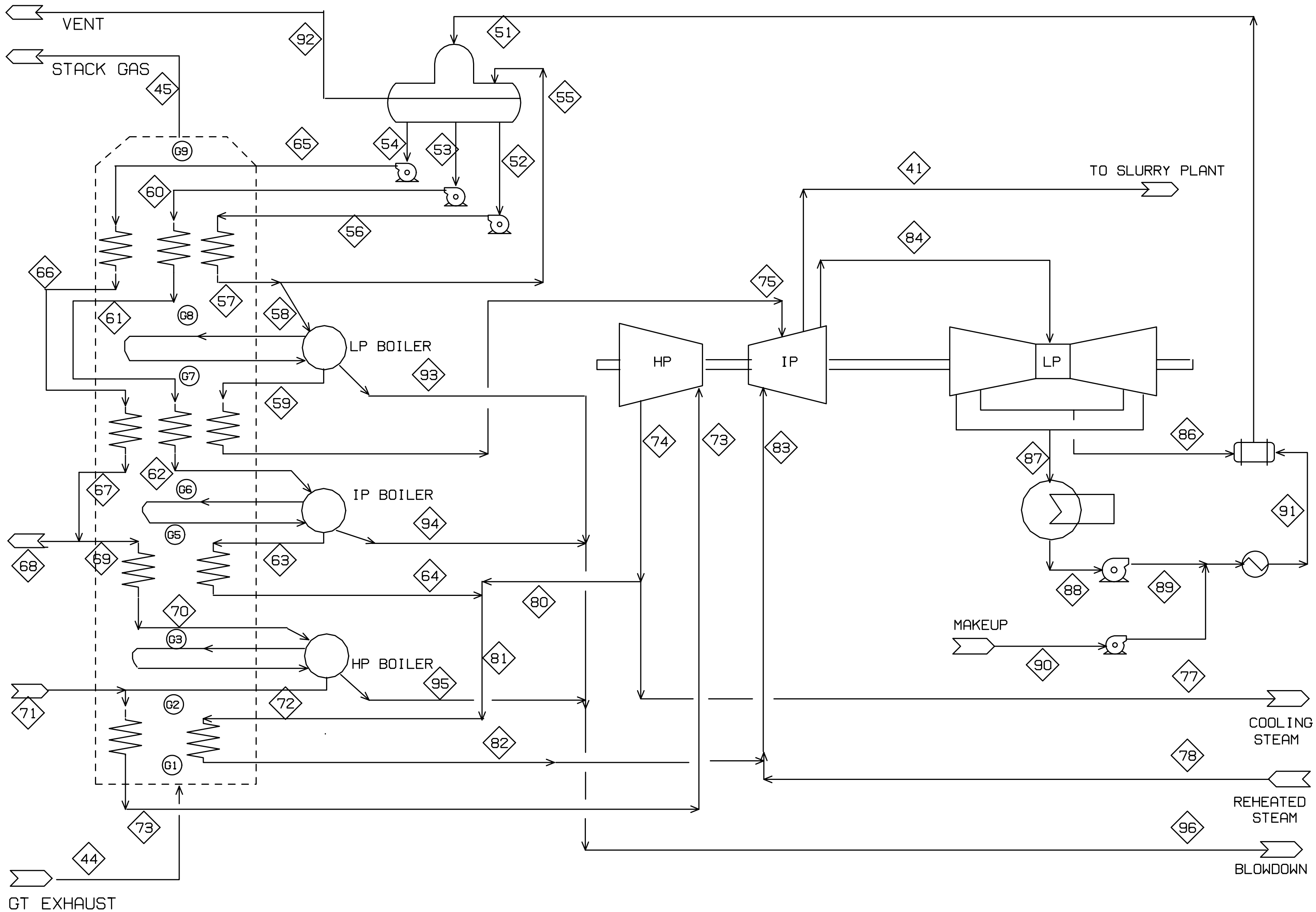
Stream PFD ID	1	1A	1B	1C	2A	2B	2	3A	3B	3C	3D	3E	3	4
ASPEN ID	COLIN	WAT1	COALB	COLA	GO2A	ASUWST	GOXYG	N2RCY	317	HOTN2	3D	N2OUT	RECYGAS	GRCYCX
Mass Flow lb/hr	345386	115085	96323	364148	266867	3949	266867	285936	340916	340916	54980	508331	235012	235012
Temperature F	59	59	350	350	60	59	204.7	62	183.7	700	60	62	1053.2	300
Pressure psi	14.7	14.7	465	465	92	14.7	472	91	300	294	265	91	346	336
H MMBtu/hr	-1081.3	-792.5	-206	-772.9	-1.2	-27.2	6.7	-3.1	6.7	51.6	-0.4	-5.5	-502.3	-572.9
					-643.6									

Stream PFD ID	5	6	7	8	9A	9B	9C	9	39	40	41	10	11	12
ASPEN ID	GRCC	DRXROUT	RAWPRD	DRAWGAZ	FNES	16	19	WSTSOL	MWATG	PURGE	STOPRE	17	18	GFLT1
Mass Flow lb/hr	235016	941443	941443	929779	11664	1231	65	51410	41853	24314	70699	939828	938815	934471
Temperature F	359.3	1900	1004	1004	1004	997	1053.2	200	59	200	863.9	997	994	1057
Pressure psi	425	412	403.8	394.5	394.5	14.7	14.7	14.7	15	15	150	394.5	366	356
H MMBtu/hr	-567.7	-1622.5	-1983.7	-1968.4	-15.3	-1.6	-0.1	-190.6	-288.2	-163.7	-382.2	-1993.8	-1993.9	-1995.6

Stream PFD ID	13	14	15	16	17	18	19	20	21	S1	S2	S3	S4	22
ASPEN ID	26	21	22	23	25C	24	27	TOFCELL	TOGT	C1	CATHIN	FLCEXIT	C3	AIR1
Mass Flow lb/hr	940047	18801	18801	18801	11281	5640	1880	399106	289008	3331258	3331258	3730363	3730363	4467600
Temperature F	1053.2	1053.2	300	436.1	409.4	409.4	409.4	1051.5	1051.5	801.6	1175	2070.4	1780.9	59
Pressure psi	346	346	336	565.6	900	900	900	345	345	282.2	273.8	260.1	252.3	14.6
H MMBtu/hr	-2009	-40.2	-45.8	-44.9	-27.1	-13.5	-4.5	-853.2	-617.9	486.9	816.8	-799.6	-1129.6	-186.5

Stream PFD ID	23	24	25	26	27	28	29	30	31	32	33	34	35	36
ASPEN ID	TOCHILL	COLAIR	AIR7	TOOXYG	ASU1	ASU6	AIRSUP	O2INX	331	REGENAIR	5A	5	SACID	ACAIR
Mass Flow lb/hr	545119	545119	2990342	642103	560311	557904	1118215	1118215	81792	81792	86116	86116	26391	18728
Temperature F	813.3	600	813.3	813.3	59	203.8	373.3	190	120	167	1443.2	850	100	59
Pressure psi	282.2	276.6	282.2	282.2	14.6	278	278	275	275.2	371	361	344	16	14.7
H MMBtu/hr	79.4	49.5	435.3	93.5	-23.4	9.3	51.6	0.9	-2.6	-1.5	-8.5	-21.7	-33.2	-0.8

Stream PFD ID	37	38	43	44	46	47	48	49	68	71
ASPEN ID	ACWAT	WGAS	POC3	GTPOC	46	47	48	49	TOGAS	FRGAS
Mass Flow lb/hr	4730	83178	4295468	4840586	5997540	666393	662070	7598425	602181	602181
Temperature F	59	100	2582.8	1185.2	1055	1055	1443.2	1059	420	635
Pressure psi	14.7	16	242.2	15.2	356	356	361	361	2116.9	1911
H MMBtu/hr	-32.6	-2.6	-1741.3	-3484	-20594.1	-2288.2	-2283.2	-24871.2	-3894.7	-3438.2


VENT
STACK GAS
GT EXHAUST
LP BOILER
IP BOILER
HP BOILER
HP
IP
LP
TO SLURRY PLANT
MAKEUP
COOLING STEAM
REHEATED STEAM
BLOWDOWN
G1
G2
G3
G5
G6
G7
G8
G9
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4/29/2002

E-GAS (DESTEC) GASIFICATION - HYBRID POWER SYSTEM
(STEAM CYCLE)
(NO CO2 SEQUESTRATION)
(58% syngas to SOFC)

Stream PFD ID	41	44	45	51	52	53	54	55	56	57	58	59	60	61
ASPEN ID	STOPRE	GTPOC	GTPC9	TODEAER	TOLP	TOIPPMP	TOHPPMP	RDEAER	TOLPEC	FRLPEC	TOLPEV	LPTOIP	TOIPEC1	TOIPEC2
Mass Flow lb/hr	70699	4840587	4840587	1103427	304518	263556	819617	291237	304518	304518	13280	13148	263556	263556
Temperature F	863.9	1185.2	256.7	205	217.3	217.3	217.3	286	217.4	286	286	305.3	218.1	286
Pressure psi	150	15.2	15	17	16.3	16.3	16.3	76.3	80.3	76.3	76.3	72.5	410.6	390
H MMBtu/hr	-382.2	-3484	-4707.8	-7385.3	-2034.4	-1760.7	-5475.6	-1925.3	-2034.3	-2013.1	-87.8	-74.7	-1760.3	-1742.2

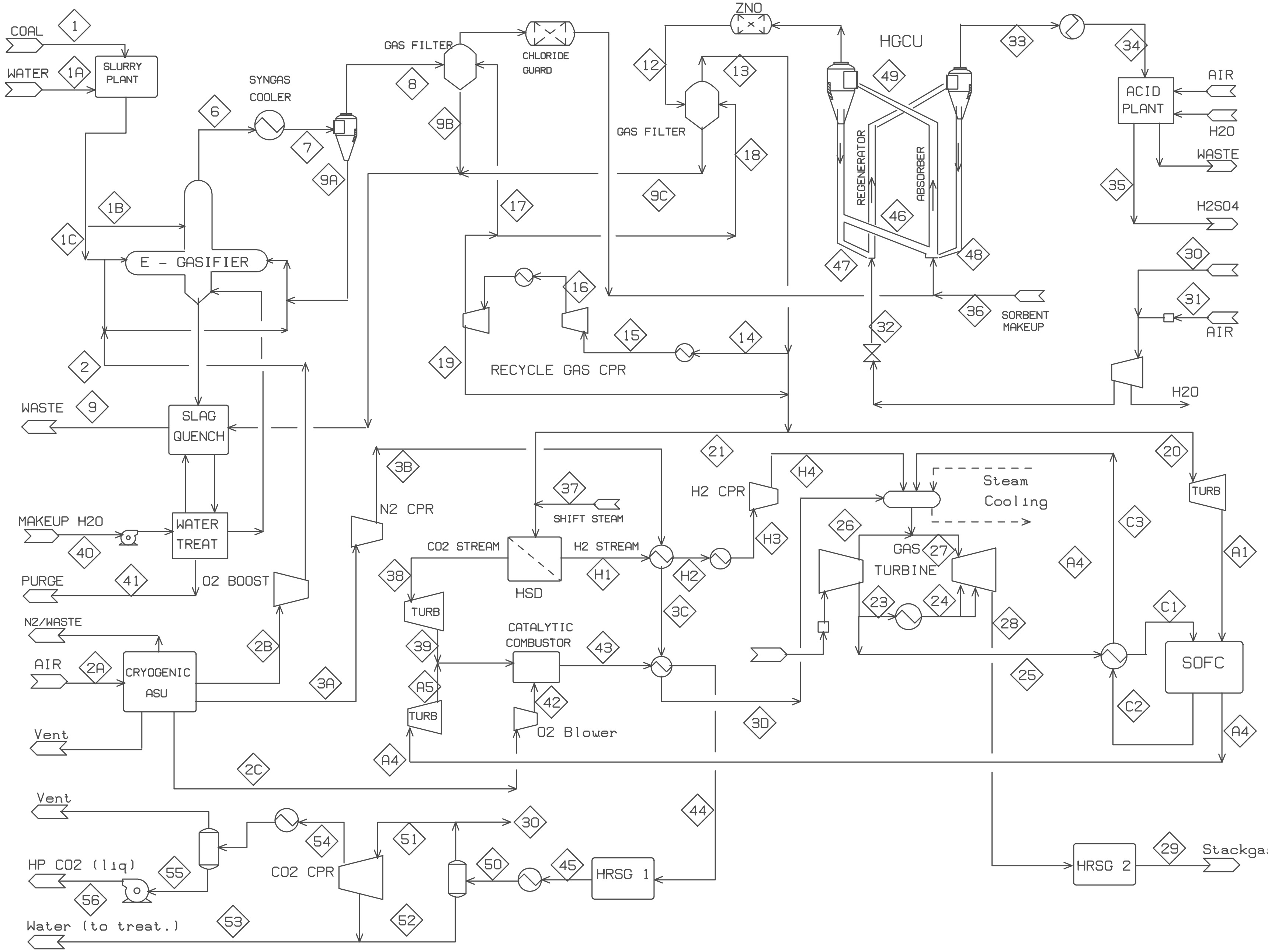
Stream PFD ID	62	63	64	65	66	67	68	69	70	71	72	73	74	75
ASPEN ID	TOIPEV	TOIPSH	FRIPSH	TOHPEC1	TOHPEC2	FRHPEC2	TOGAS	TOHPEC3	TOHPEV	FRGAS	TOHPSH	TOHPTUR	FRHPTUR	713
Mass Flow lb/hr	263556	260921	260921	819617	819617	819617	602181	217436	217436	602181	215262	817443	817443	13148
Temperature F	420	432.3	620	221.1	286	420	420	420	620	635	629.3	1099.3	645	420
Pressure psi	370.5	352	350	2345.6	2228.3	2116.9	2116.9	2116.9	2011.1	1911	1910.5	1800	350	69.5
H MMBtu/hr	-1705.1	-1477.5	-1446.5	-5468.3	-5415	-5301	-3894.7	-1406.3	-1352.8	-3438.2	-1231.6	-4353.1	-4520.5	-73.9

Stream PFD ID	77	78	80	81	82	83	84	86	87	88	89	90	91	92
ASPEN ID	TOSTAT	FRGT	FRHPS	TOREHT	TOIPMIX	TOIPTUR1	TOLPTUR1	314	TOCOND	TOCPMP	TOFWH	MAKUP	FRFWHTR	DEBLOW
Mass Flow lb/hr	70000	70000	747443	1008364	1008364	1078364	1020812	39378	981434	981434	981434	82615	1064049	6973
Temperature F	645	1095.6	645	638.5	1100	1099.7	515.7	379.7	88.8	87.9	87.9	80	165.9	217.3
Pressure psi	350	342	350	350	342	342	35	17	0.7	0.7	40	14.7	17	16.3
H MMBtu/hr	-387.1	-370.3	-4133.4	-5579.9	-5332.2	-5702.5	-5689.5	-222	-5724.3	-6683.7	-6683.5	-563.3	-7163.4	-39.8

Stream PFD ID	93	94	95	96	G1	G2	G3	G5	G6	G7	G8	G9
ASPEN ID	LPBLOW	IPBLOW	HPBLOW	TBLOW	GTPC1	GTPC2	GTPC3	GTPC5	GTPC6	GTPC7	GTPC8	GTPC9
Mass Flow lb/hr	133	2636	2174	4943	4840586	4840586	4840586	4840586	4840586	4840586	4840586	4840587
Temperature F	305.3	432.3	629.3	213	1185.2	772.1	690.5	625.7	461.7	341	331.3	256.7
Pressure psi	72.5	352	1910.5	15	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15
H MMBtu/hr	-0.9	-17	-13.5	-31.4	-3484	-4048.5	-4156.1	-4240.6	-4451.2	-4603.1	-4615.3	-4707.8

Hybrid Cycles (Turbine / SOFC)

Destec High Pressure (E-Gas^{TM}) / HGCU / "G" GT / CO_2 Capture



COAL
WATER
SLURRY PLANT
E - GASIFIER
SYNGAS COOLER
GAS FILTER
CHLORIDE GUARD
ZNO
HGCU
REGENERATOR
ABSORBER
GAS FILTER
ACID PLANT
AIR
H2O
WASTE
H2SO4
SORBENT MAKEUP
AIR
H2O
RECYCLE GAS CPR
WASTE
SLAG QUENCH
MAKEUP H2O
WATER TREAT
PURGE
O2 BOOST
N2/WASTE
AIR
CRYOGENIC ASU
Vent
N2 CPR
SHIFT STEAM
CO2 STREAM
H2 STREAM
HSD
TURB
CATALYTIC COMBUSTOR
TURB
O2 Blower
H2 CPR
Steam Cooling
GAS TURBINE
TURB
SOFC
Vent
HP CO2 (liq)
Water (to treat.)
CO2 CPR
HRSG 1
HRSG 2
Stackgas

4/30/2002

E-GAS (DESTEC) GASIFICATION - HYBRID POWER SYSTEM

(GAS TURBINE / HGCU//SOFC/STEAM CYCLE)

(CO2 SEQUESTRATION)

	POWER kW		
GAS TURBINE	-272.5	LHV EFFICIENCY	49.7 %
SOFC	-324.1		
STEAM TURBINE	-226.1	HHV EFFICIENCY	47.9 %
MISC (generated)	-121.2		
MISC (required)	166.1		
AUX	23.3		
NET POWER	-754.6		

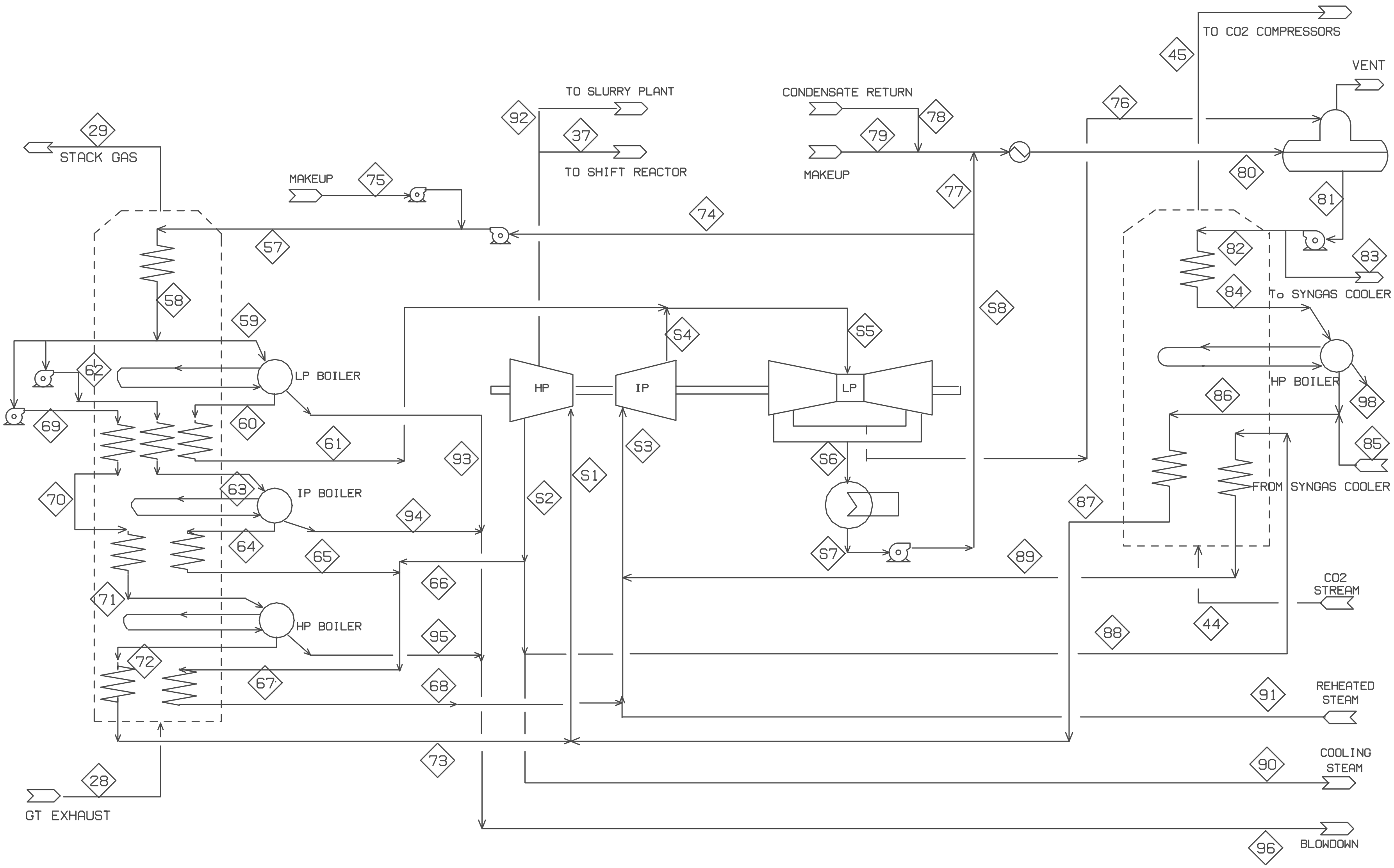
Stream PFD ID	1	1A	1B	1C	2A	2b	2	2C	3A	3B	3C	3D	6	7	8
ASPEN ID	COLIN	WAT1	COLB	COLA	AIRASU	GO2A	GOXYG	O2LP	3A	35	68	HOTN2	DRXROUT	RAWPRD	DRAWGAZ
Mass Flow lb/hr	460812	153546	128514	485844	1836831	307420	307420	97608	460000	458841	458841	458841	893884	893884	878321
Temperature F	59	59	350	350	59	60	289.4	60	60	287.1	1300	1900	1904.7	1110	1110
Pressure psi	14.7	14.7	1078	1078	14.6	18	1150	16.5	18	260	255	250	1034	1024	1019
H MMBtu/hr	-1442.7	-1057.3	-286	-1070.9	-76.7	-1.2	13	-0.4	-23.4	8.8	131	209.2	-1421.9	-1738.1	-1718.1

Stream PFD ID	9B	9C	9	40	41	10	11	12	13	14	15	16	17	18	19
ASPEN ID	16	19	WSTSOL	MWATG	PURGE	17	18	TOGFLT	26	21	22	23	25C	24	27
Mass Flow lb/hr	1643	856	69360	55841	32439	888029	886677	881653	886918	17738	17738	17676	11351	6121	17
Temperature F	1100.4	1134.6	200	59	200	1100.4	1096.4	1139.9	1134.6	1134.6	300	344.9	334.3	334.3	334.3
Pressure psi	14.7	14.7	14.7	15	15	1000	985	975	965	965	955	1146	1291.2	1291.2	1291.2
H MMBtu/hr	-2.1	-3.3	-257.7	-384.5	-218.4	-1742.1	-1742.2	-1763.4	-1774.2	-35.5	-41.8	-41	-26	-14	0

Stream PFD ID	21	A1	A4	A5	C1	C2	C3	22	23	24	25	26	27	28	29
ASPEN ID	TOSHFT	A1	A4	A5	C1	C2	C3	AIR1	TOCHILL	COLAIR	2AX	2B	TOHPGT	GTPCX	34X
Mass Flow lb/hr	365061	504131	799622	799622	3638756	3343264	3343264	4467600	545119	545119	3638756	276276	4107854	4660422	4660422
Temperature F	1134.6	777.8	1831.9	1176.5	1075	1832	1567.6	59	813.2	600	813.2	813.2	2582.6	1105.6	208.5
Pressure psi	964	282.3	252.3	25	273.8	260.1	252.3	14.6	282.2	277	282.2	282.2	242.2	15	14.7
H MMBtu/hr	-730.3	-1085.6	-2837.1	-3034.3	780.7	1415	1163.9	-186.6	79.3	49.5	529.6	40.2	1403.8	-325.3	-1447.3

Stream PFD ID	31	32	33	34	35	36	37	38	39	H1	H2	H3	H4	42	43
ASPEN ID	RAIR	39	5A	5	SACID	ZNMKUP	SHFSTM	CO2RICH	CO2CMB	H2PRD	S10	S28	H2GT	O2CAT	CATOUT
Mass Flow lb/hr	72295	148931	154711	154711	35607	770	195946	531518	531518	29485	29485	29485	29485	97608	1428748
Temperature F	59	260.9	1391.8	850	100	100	875	1393.5	556.2	1393.5	127.7	85	312	136.4	2142.9
Pressure psi	14.6	971	955	940	16	985	1000	950	20.5	20.5	19.6	18.5	300	25	19.5
H MMBtu/hr	-3	-287.3	-287.6	-310.3	-44.3	-3.4	-1065.1	-1923.4	-2069	126.3	4.1	0.1	21.8	1.3	-5102

Stream PFD ID	45	46	47	48	49	50	51	52	53	54	55	56
ASPEN ID	S11	46	47	48	49	S35	TOCO2CPR	FLSH2O	WSTH2O	CO2PROD	29	CO2LIQ
Mass Flow lb/hr	1428748	11005772	1222864	1217084	13110303	1428746	1023486	327456	338819	1012124	1012124	1012124
Temperature F	275	1139.2	1139.2	1391.8	1139.9	80	80	80	80.7	268.3	100	122.9
Pressure psi	18.7	975	975	955	954	14.8	14.8	14.8	14.8	2100	2060	3000
H MMBtu/hr	-6017.8	-37618.5	-4179.8	-4181.5	-43559.8	-6451.1	-3907.7	-2246.4	-2323.9	-3837.8	-3937.7	-3931.3



STEAM CYCLE
(CO2 SEQUESTRATION)

E-GAS (DESTEC) GASIFICATION - HYBRID POWER SYSTEM
(STEAM CYCLE)
(CO2 SEQUESTRATION)

Stream PFD ID	57	58	59	60	61	62	63	64	65	66	67	68	69	70
ASPEN ID	TOLPEC	HOTLP	TOLPEV	TOLPSH	LPTOIP	TOIPEC	TOIPEV	TOIPSH	FRIPSH	6	TOREHT	TOIPTUR1	TOHPEC1	TOHPEC2
Mass Flow lb/hr	734450	734450	90447	89542	89542	176219	176219	174457	174457	383106	557564	557564	467784	467784
Temperature F	90	295	295	299.3	400	296.4	463	472.8	615	712	680.8	1050	299.9	463
Pressure psi	73.5	66.3	66.3	66.3	63	585.7	556.4	528.6	518	518	518	492	2263.9	2150.7
H MMBtu/hr	-5000	-4848.6	-597.1	-509.2	-504.4	-1162.9	-1131.6	-987.8	-969.9	-2108.3	-3078.2	-2965.6	-3083.9	-3003.5

Stream PFD ID	71	72	73	74	75	76	77	78	79	80	81	82	83	84
ASPEN ID	TOHPEV	TOHPSH	TOHPTUR	3	MAKUP	LPTODEA	TOMIX	SLURCND	MKUP	TODEAER	TOPMPHP	TSTMCO2	TOSYNCOL	TOBLR
Mass Flow lb/hr	467784	463106	463106	727106	7345	13900	480230	135216	204856	820301	830031	473875	356156	473875
Temperature F	615	631.5	1050	90	80	322	91	180	80	205	217.3	221	221	620
Pressure psi	2043.1	1941	1800	20	20	17.5	20	20	20	17.1	16.3	2345.6	2345.6	2011.1
H MMBtu/hr	-2914.1	-2650.7	-2480	-4950.1	-50.1	-78.7	-3268.9	-908.4	-1396.7	-5490.3	-5545.2	-3161.6	-2376.2	-2948.2

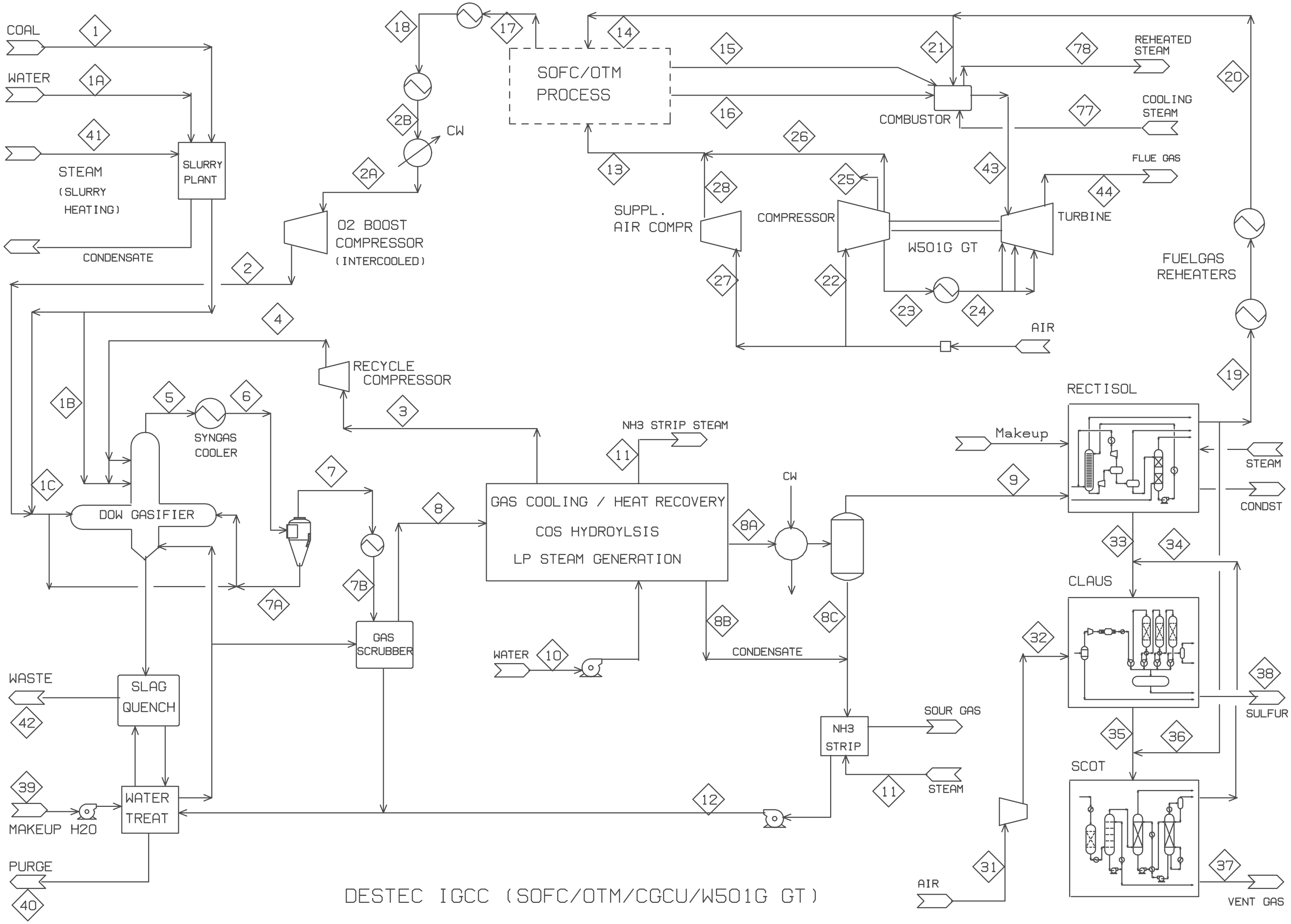
Stream PFD ID	85	86	87	88	89	90	91	92	93	94	95	96	97	98
ASPEN ID	FRSYNCOL	S19	HPTURIN	HPTUREX	IPTURIN	COLSTM	REHSTM	SLURSTM	LPBLOW	IPBLOW	HPBLOW	TBLOW	DVENT	BLDWN
Mass Flow lb/hr	356156	825292	825292	494130	494130	80000	80000	135216	904	1762	4678	7345	4171	4739
Temperature F	635	631.7	1050	709.8	1050	712	1050	879.1	299.3	472.8	631.5	213	217.3	629.3
Pressure psi	1911	1910.5	1800	518	492.1	518	492	1000	66.3	528.6	1941	15	16.3	1910.5
H MMBtu/hr	-2033.5	-4717.7	-4419.5	-2719.8	-2628.2	-440.2	-425.5	-734.2	-6	-11.3	-29	-46.3	-23.8	-29.4

Stream PFD ID									S1	S2	S3	S4	S5	S6
ASPEN ID	TOIPMX2	IPTUREX	TOCOND	VLPEX	TOCPMP	CNDOUT	3	TOMIX						
Mass Flow lb/hr	637564	494130	727106	480230	727106	480230	727106	480230	1288398	957236	1131694	1131694	1221236	1207336
Temperature F	555.8	555.8	93.6	92.3	90	91	90	91	1050	712	1050	555.8	544.3766	92.3
Pressure psi	63	63	0.8	0.8	0.7	0.7	20	20	1800	518	492	63	63	0.8
H MMBtu/hr	-3542.4	-2745.5	-4253.6	-2807.6	-4950.1	-3268.9	-4950.1	-3268.9	-6899.5	-5268.3	-6019.3	-6287.9	-6792.3	-7061.2

Stream PFD ID	S7	S8
ASPEN ID		
Mass Flow lb/hr	1207336	1207336
Temperature F	90	90
Pressure psi	0.7	20
H MMBtu/hr	-8219	-8219

Hybrid Cycles (Turbine / SOFC)

Destec (E-Gas^{TM}) / OTM / CGCU / "G" GT / No CO_2 Capture


COAL
WATER
STEAM
STEAM (SLURRY HEATING)
SLURRY PLANT
CONDENSATE
O2 BOOST COMPRESSOR (INTERCOOLED)
CW
SOFC/OTM PROCESS
COMBUSTOR
REHEATED STEAM
COOLING STEAM
FLUE GAS
SUPPL. AIR COMPR
COMPRESSOR
W501G GT
TURBINE
FUELGAS REHEATERS
AIR
RECYCLE COMPRESSOR
SYNGAS COOLER
DOW GASIFIER
NH3 STRIP STEAM
GAS COOLING / HEAT RECOVERY
COS HYDROLYSIS
LP STEAM GENERATION
RECTISOL
Makeup
STEAM
CONDST
CLAUS
GAS SCRUBBER
WATER
CONDENSATE
WASTE
SLAG QUENCH
SOUR GAS
NH3 STRIP
SULFUR
MAKEUP H2O
WATER TREAT
SCOT
PURGE
VENT GAS
DESTEC IGCC (SOFC/OTM/CGCU/W501G GT)

E-GAS (DESTEC) GASIFICATION - HYBRID POWER SYSTEM

(NO CO2 SEQUESTRATION)

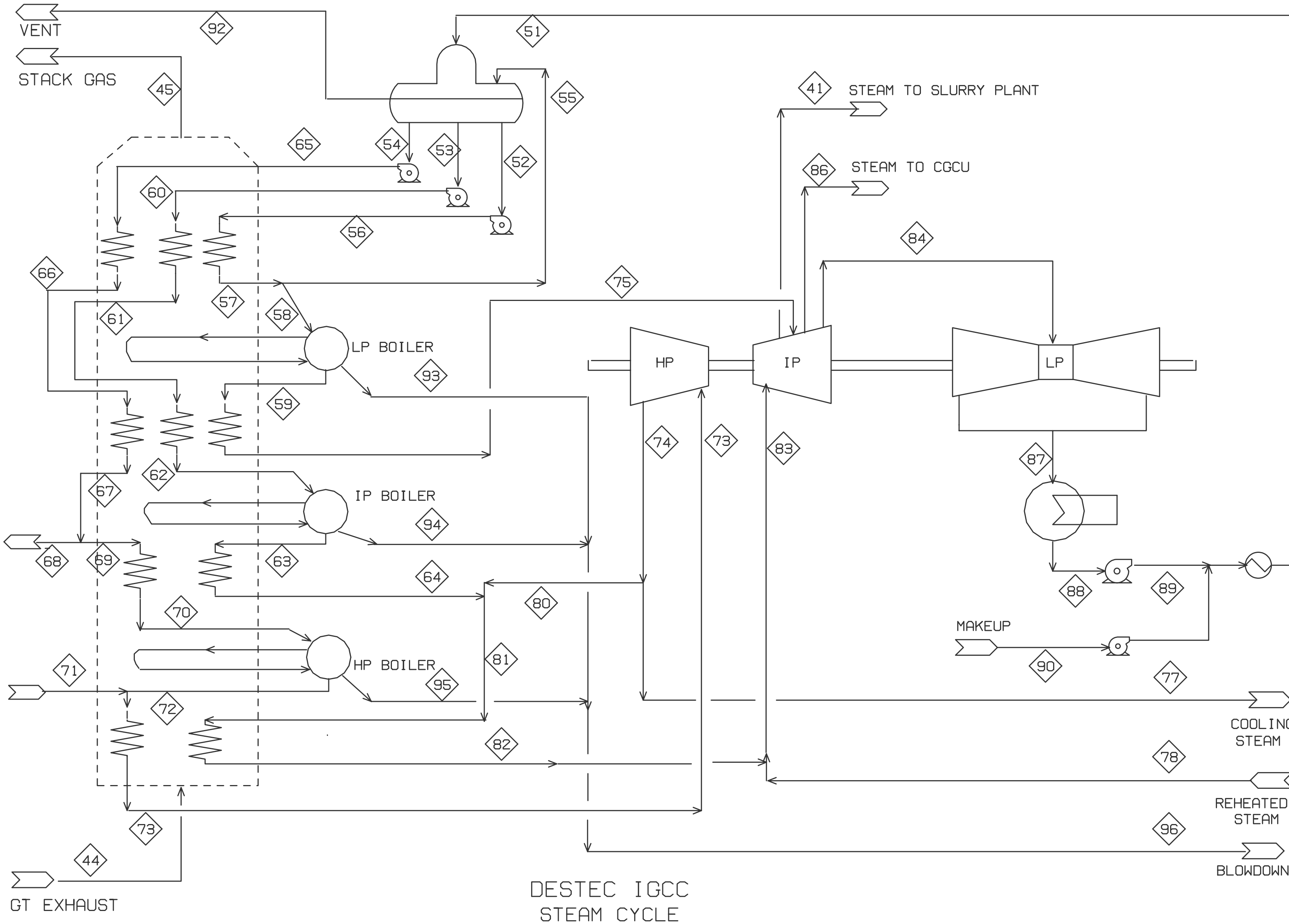
SUMMARY:	MWe	EFFICIENCY:	%
GAS TURBINE	272.7	LHV	57.02
STEAM TURBINE	189.8	HHV	54.99
SOFC POWER	254.4		
MISCELLANEOUS	-20.9		
GROSS POWER	696		
AUXILIARY (3%)	-20.9		
NET POWER	675.2		

STREAM	1	1A	1B	1C	2	2A	2B	3	4	5	6	7	7A	7B	8
Temperature (F)	59	59	350	350	223.8	80	140	303.7	332.9	1900	650	649.9	649.9	415	303.3
Pressure (PSIA)	14.7	14.7	465	465	472	10	11	378	425	412	403.8	394.5	394.5	390	380
Flow (LB/HR)	359277	119714	100197	378794	257095	257095	257095	189561	189560	903894	903894	891761	12134	891761	947803
Flow (LBMOL/HR)		6645			8035	8035	8035	9795	9795						48977
H (MM BTU/HR)	-1124.8	-824.3	-211.5	-794.3	7.7	0.1	3.5	-502.8	-500.7	-1598.2	-2082.1	-2065	-17.1	-2148.6	-2514.1

STREAM	8A	8B	8C	9	10	11	12	13	14	15	16	17	18	19	20
Temperature (F)	190	231.9	101.8	103	59	280	212.4	812.1	790	790	1660	1661.2	588	116	790
Pressure (PSIA)	354	354	20	349	14.7	37	470	282.2	330	330	276	13	12.5	340	330
Flow (LB/HR)	634804	123439	15499	619305	62183	62183	137792	3818369	344226	0	3905498	257095	257095	584357	584357
Flow (LBMOL/HR)	32331	6850	830	31501	3452	3452	7649	132322	17950	0	134096	8035	8035	30472	30472
H (MM BTU/HR)	-1335.9	-826.4	-99.7	-1272	-428.2	-353.6	-925.7	555.2	-606.4	0	-1034	100.1	30	-1182.6	-1029.4

STREAM	21	22	23	24	25	26	27	28	31	32	33	34	35	36	37
Temperature (F)	790	59	812.1	600	812.1	812.1	59	812.4	59	161	156.2	70	419.6	116	70
Pressure (PSIA)	330	14.6	282.2	276.6	282.2	282.2	14.6	282.2	14.7	25	18.5	17.5	26.7	340	17.5
Flow (LB/HR)	240131	4320000	527109	527109	13478	3779413	38956	38956	19759	19759	32640	2589	46154	6712	50276
Flow (LBMOL/HR)	12522	149706	18266	18266	467	130972	1350	1350	685	685	923	61	1530	350	1816
H (MM BTU/HR)	-423	-180.5	76.6	47.9	2	549.6	-1.6	5.7	-0.8	-0.3	-97.7	-9	-130.6	-13.6	-149.2

STREAM	38	39	40	41	42	43	44	45
Temperature (F)	285	59	200	819.9	200	2583.5	1135.2	259.7
Pressure (PSIA)	14.7	14.7	15	150	15	268.5	15.2	15
Flow (LB/HR)	8834	52508	120578	73226	47563	4145629	4672738	4672738
Flow (LBMOL/HR)	276	2915	6684	4065		140938	159204	159204
H (MM BTU/HR)	-0.9	-361.5	-809.3	-397.8	-158.5	-1505.6	-3209.9	-4311.7


VENT
STACK GAS
92
45
51
55
41
STEAM TO SLURRY PLANT
86
STEAM TO CGCU
65
54
53
52
60
56
66
84
61
57
58
LP BOILER
75
93
59
HP
IP
LP
74
73
83
87
62
IP BOILER
67
94
68
69
63
64
80
88
89
70
MAKEUP
81
90
71
HP BOILER
95
77
72
COOLING
STEAM
82
78
REHEATED
STEAM
73
96
44
BLOWDOWN
GT EXHAUST
DESTEC IGCC
STEAM CYCLE

E-GAS (DESTEC) GASIFICATION - HYBRID POWER SYST

(NO CO2 SEQUESTRATION)

STEAM CYCLE PROCESS STREAMS

STREAM	41	44	45	51	52	53	54	55	56	57	58	59	60	61	62
Temperature (F)	819.9	1135.2	259.7	205	217.3	217.3	217.3	286	217.4	286	286	305.3	218.1	286	420
Pressure (PSIA)	150	15.2	15	17	16.3	16.3	16.3	76.3	80.3	76.3	76.3	72.5	410.6	390	370.5
Flow (LB/HR)	73226	4672738	4672738	1080557	298115	238664	822063	285113	298115	298115	13001	12871	238664	238664	238664
Flow (LBMOL/HR)	4065	159204	159204	59979	16548	13248	45631	15826	16548	16548	722	714	13248	13248	13248
H (MM BTU/HR)	-397.8	-3209.9	-4311.7	-7236.7	-1992.9	-1595.4	-5495.4	-1886	-1992.8	-1972	-86	-73.2	-1595	-1578.6	-1545

STREAM	63	64	65	66	67	68	69	70	71	72	73	74	75	77	78
Temperature (F)	432.3	620	221	286	420	420	420	620	635	629.3	1050	606.4	420	606.4	1056
Pressure (PSIA)	352	350	2345.6	2228.3	2116.9	2116.9	2116.9	2011.1	1910.5	1910.5	1800	350	69.5	350	342
Flow (LB/HR)	236277	236277	822063	822063	822063	676759	145304	145304	676759	143851	820610	820610	12871	70000	70000
Flow (LBMOL/HR)	13115	13115	45631	45631	45631	37565	8066	8066	37565	7985	45550	45550	714	3886	3886
H (MM BTU/HR)	-1338.9	-1310.9	-5488.1	-5434.5	-5320.2	-4379.8	-940.4	-904.6	-3866.7	-823.6	-4398	-4559	-72.4	-388.9	-372.1

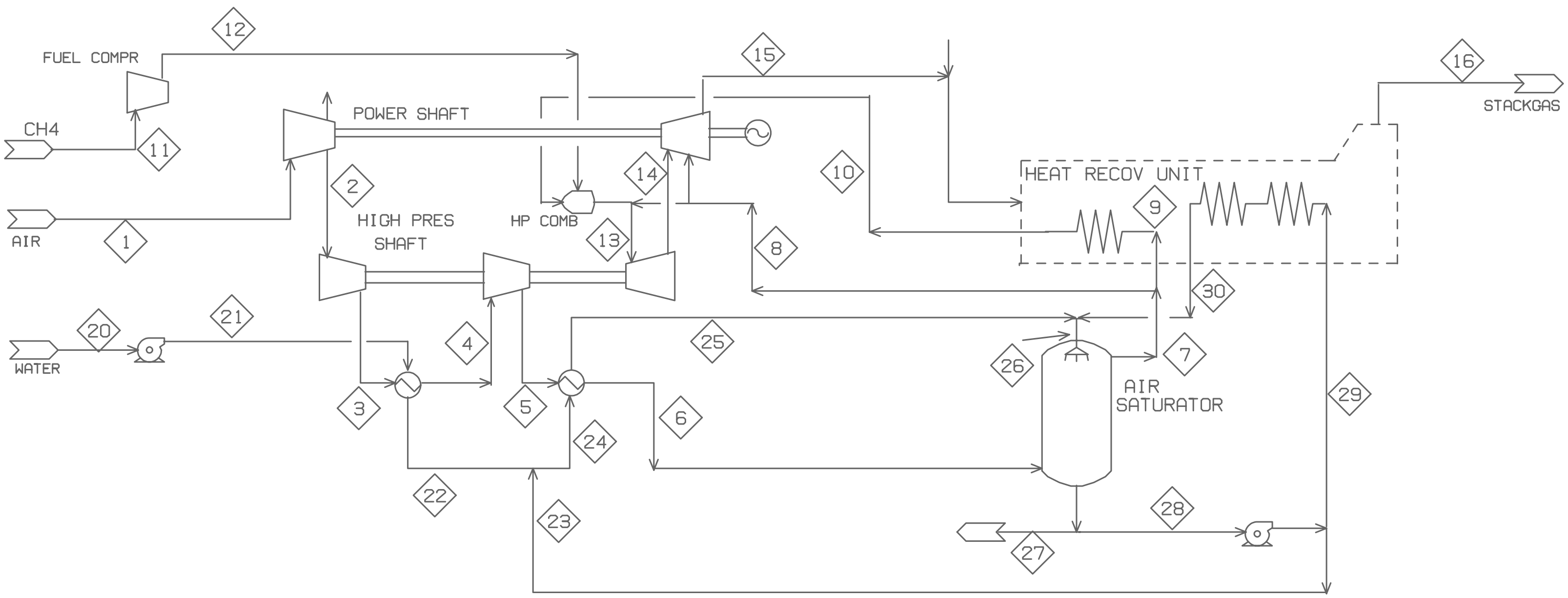
STREAM	80	81	82	83	84	86	87	88	89	90	92	93	94	95	96
Temperature (F)	606.4	609.6	1050	1050.4	481.4	596	88.8	87.9	87.9	60	217.3	305.3	432.3	629.3	213
Pressure (PSIA)	350	350	342	342	35	60	0.7	0.7	40	14.7	16.3	72.5	352	1910.5	15
Flow (LB/HR)	750610	986887	986887	1056887	886460	110073	886460	886460	886460	194097	6828	130	2387	1453	3970
Flow (LBMOL/HR)	41665	54780	54780	58665	49205	6110	49205	49205	49205	10774	379	7	132	81	220
H (MM BTU/HR)	-4170.1	-5481	-5249.3	-5621.4	-4958.9	-609.8	-5182.8	-6040.7	-6040.6	-1328.1	-39	-0.9	-15.4	-9	-25.3

Humid Air Turbine (HAT)

Natural Gas / Pratt Whitney GT

Natural Gas HAT Cycle

(based on PW turbine)



NATURAL GAS HAT CYCLE (based on PW turbine)

Gas Turb	326.5	MWe
Misc	3.0	MWe
Auxiliary	4.9	MWe
Net Power	318.7	MWe
Eff (HHV)	51.9	%
Eff (LHV)	57.6	%

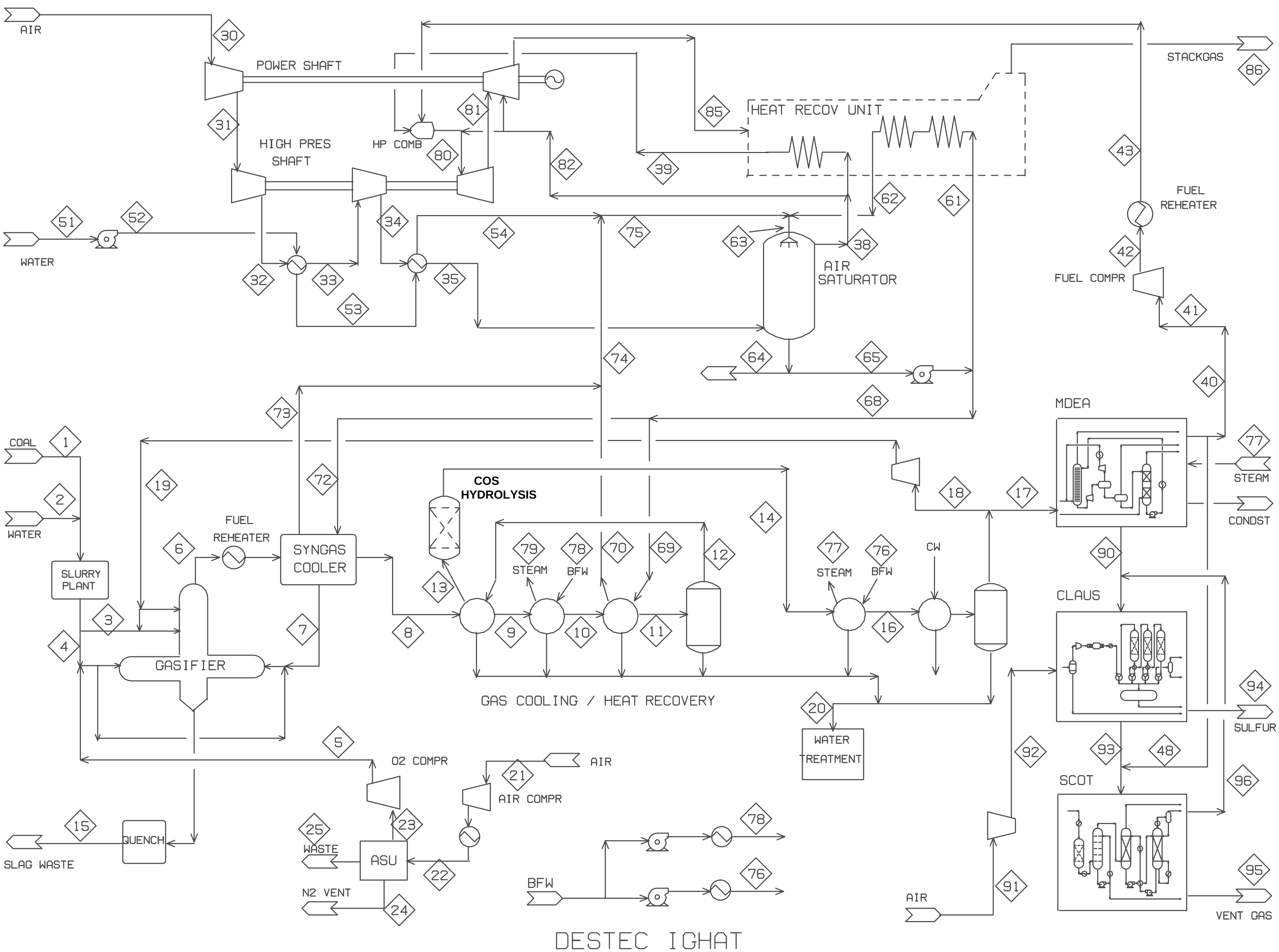
STREAM ID	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Temperature F	59	128.9	269.6	90	876.8	254	374.1	374.1	374.1	910	60	234.3	2750	2244.6
Pressure psi	14.54	21.81	43.62	39.62	796.9	765.3	742.4	742.4	742.4	727.5	250	780	691	275.13
Mass Flow lb/hr	2315881	2244960	2244960	2244960	2244960	2244960	2761017	335161	2425856	2425856	87727	87727	2679152	2679152
Mass Flow lb/sec	643.3	623.6	623.6	623.6	623.6	623.6	766.9	93.1	673.8	673.8	24.4	24.4	744.2	744.2
Mole Flow lbmol/hr	80268.5	77810.5	77810.5	77810.5	77810.5	77810.5	106463.7	12923.7	93540	93540	5468.3	5468.3	105392.6	105392.6
Enthalpy MMBtu/hr	-100.4	-59.5	17.1	-81	362.4	2.5	-2859	-347.1	-2512	-2110.4	-176.8	-168.9	-2450.7	-2978.6
Substream: MIXED														
Cp Btu/lb-R	0.242	0.242	0.244	0.243	0.263	0.257	0.31	0.31	0.31	0.314	0.555	0.641	0.395	0.382

STREAM ID	15	16	20	21	22	23	24	25	26	27	28	29	30
Temperature F	993.3	274.9	59	60.1	228	228.7	228.3	499.8	499.9	228.8	228.8	228.7	500
Pressure psi	15.49	15.2	14.7	815	798	804	798	783	783	744.4	744.4	804	783
Mass Flow lb/hr	2848744	2919664	540452	540452	540452	559761	1100213	1100213	1824139	24392	1283687	723926	723926
Mass Flow lb/sec	791.3	811	150.1	150.1	150.1	155.5	305.6	305.6	506.7	6.8	356.6	201.1	201.1
Mole Flow lbmol/hr	111932	114390.1	29999.6	29999.6	29999.6	31071.5	61071.1	61071.1	101255.1	1346.2	71255.5	40184	40184
Enthalpy MMBtu/hr	-4323.3	-4963.6	-3719.3	-3717.4	-3619.4	-3748.3	-7367.7	-7007.7	-11618.4	-161.1	-8595.8	-4847.6	-4610.7
Substream: MIXED													
Cp Btu/lb-R	0.33	0.297	1.078	1.076	1.097	1.098	1.097	1.422	1.423	1.086	1.098	1.098	1.423

Humid Air Turbine (HAT)

Coal Syngas / Destec (E-Gas^{TM}) / CGCU / Pratt Whitney GT

ASPEN IGHAT System



IGHAT
Destec Gasifier
(slurry - 2 stage)

Gas Turb	457.6	MWe
Misc	44.0	MWe
Auxiliary	6.2	MWe
Net Power	407.3	MWe
Eff (HHV)	43.3	%
Eff (LHV)	44.9	%

Stream PFD ID	1	2	3	4	5	6	7	8	9	10	11	12	13	14	16
ASPEN ID	COALIN	WATERI	COALB	COALA	GASIFOXY	RXROUT	FINRCY	RAWGAZ	TOQR2	TOQR3	TOQR4	TOQR1A	TOCOS	TOQR5	TOQR7
Temperature F	59	59	350	350	291.4	1900	750	750	675	504.7	460	455	531.4	532	270
Pressure psi	14.7	14.7	465	465	464.1	412	418	407	402	397	392	387	382	380	370
Mass Flow lb/hr	275022	91639	76699	289961	208466	695583	10320	685263	685263	685263	685263	685263	685263	685263	685263
Mass Flow lb/sec	76.4	25.5	21.3	80.5	57.9	193.2	2.9	190.4	190.4	190.4	190.4	190.4	190.4	190.4	190.4
Mole Flow lbmol/hr		5086.8			6475.7			34766.7	34766.7	34766.7	34766.7	34766.7	34766.7	34766.7	34766.7
Enthalpy MMBtu/hr	-861	-630.7	-155	-583.5	9.4	-1108.1	-1.4	-1429.5	-1449.9	-1495.6	-1507.5	-1508.8	-1488.5	-1488.5	-1557.8
Substream: MIXED															
Cp Btu/lb-R		1.078			0.229	0.444		0.398	0.395	0.389	0.388	0.388	0.39	0.39	0.384

Stream PFD ID	17	18	19	20	21	22	23	24	25	30	31	32	33	34	35
ASPEN ID	TOCGCU	RECYGAS	GRCYC	TOSTRIP	AIRO2	ATASU2	GASO2A	VENTN2	WSTASU	GTAIR	AIRTHP	AIR1	AIR2	AIR6	AIR7
Temperature F	103	103	131.8	103.5	59	103	60	84	84	59	128.9	269.6	90	876.8	254
Pressure psi	365	365	425	20	14.54	88	16.5	15	15	14.54	21.81	43.62	39.62	796.9	785.7
Mass Flow lb/hr	485558	136952	136952	62754	898773	898773	208466	684876	5430	2315880	2244960	2244960	2244960	2244960	2244960
Mass Flow lb/sec	134.9	38	38	17.4	249.7	249.7	57.9	190.2	1.5	643.3	623.6	623.6	623.6	623.6	623.6
Mole Flow lbmol/hr	24420.2	6887.7	6887.8	3458.7	31151.5	31151.5	6475.7	24373.4	301.4	80268.5	77810.5	77810.5	77810.5	77810.5	77810.5
Enthalpy MMBtu/hr	-969.2	-273.4	-272	-423.7	-39	-29.9	-0.8	-2.3	-37.2	-100.4	-59.5	17.1	-81	362.4	2.4
Substream: MIXED															
Cp Btu/lb-R	0.371	0.371	0.373	1.064	0.242	0.244	0.216	0.248	1.077	0.242	0.242	0.244	0.243	0.263	0.257

Stream PFD ID	38	39	40	42	43	48	51	52	53	54	61	62	63	64	65
ASPEN ID	TOCO1	TOCOMB	FRSELEX	HPCPR	HPFUEL	REDGAS	WAT51	WAT52	WAT53	WAT54	WAT61	WAT62	WAT63	WAT64	WAT65
Temperature F	403.2	910	116	297	797.6	116	59	60.1	161.5	500	255.2	500	497.9	254.8	254.8
Pressure psi	742.4	727.5	319	780	757	319	14.7	815	798	783	804	783	783	744.4	744.4
Mass Flow lb/hr	3100276	2765227	448570	448570	448570	6755	899427	899427	899427	899427	1397524	1397524	3200708	43896	2301384
Mass Flow lb/sec	861.2	768.1	124.6	124.6	124.6	1.9	249.8	249.8	249.8	249.8	388.2	388.2	889.1	12.2	639.3
Mole Flow lbmol/hr	125307.8	111765.1	23240.4	23240.4	23240.4	350	49925.8	49925.8	49925.8	49925.8	77574.4	77574.4	177666.3	2418.9	127746.2
Enthalpy MMBtu/hr	-4760.7	-3777.6	-884.4	-854.2	-766.2	-13.3	-6189.7	-6186.6	-6088.6	-5728.5	-9317.3	-8900.9	-20395.2	-287.6	-15344.6
Substream: MIXED															
Cp Btu/lb-R	0.337	0.338	0.378	0.388	0.398	0.378	1.078	1.076	1.08	1.423	1.108	1.423	1.416	1.093	1.108

Stream PFD ID	68	69	70	72	73	74	75	76	77	78	79	80	81	82	85
ASPEN ID	WAT68	WAT69	WAT70	WAT72	WAT73	WAT74	WAT75	HTWCG	SHSCG	HTWUT	SHS115	POCX	POC3	ABLEED	GTPOC
Temperature F	255.2	255.2	397.8	255.2	500	492.4	496.2	250	265	250	375	2750.2	2364.4	403.2	1034.6
Pressure psi	804	804	783	804	783	783	783	35	30	165	160	691	335.53	742.4	15.2
Mass Flow lb/hr	903757	72301	72301	831457	831457	903757	1803184	71217	71217	43895	43895	3379367	3379367	335161	3619879
Mass Flow lb/sec	251	20.1	20.1	231	231	251	500.9	19.8	19.8	12.2	12.2	938.7	938.7	93.1	1005.5
Mole Flow lbmol/hr	50166.1	4013.3	4013.3	46152.9	46152.9	50166.1	100091.9	3953.2	3953.2	2436.5	2436.5	131289.7	131289.7	13546.6	140602.4
Enthalpy MMBtu/hr	-6025.3	-482	-470.1	-5543.3	-5295.6	-5765.7	-11494.3	-475.3	-405.2	-293	-248	-4798.1	-5326	-514.6	-7210.7
Substream: MIXED															
Cp Btu/lb-R	1.108	1.108	1.219	1.108	1.423	1.4	1.411	1.11	0.461	1.109	0.49	0.408	0.398	0.337	0.34

Stream PFD ID	86	90	91	92	93	94	95	96
ASPEN ID	STACK	AG-CLUS1	HPCAIR	AIRTCL	CL-TAIL1	CLAUSULF	TG-SCOTC	TG-SCOTR
Temperature F	273.2	141.1	59	171.7	439.2	285	70	70
Pressure psi	14.8	18.5	14.7	25	26.7	14.7	17.5	17.5
Mass Flow lb/hr	3619879	33506	15161	15161	43849	6802	48620	1985
Mass Flow lb/sec	1005.5	9.3	4.2	4.2	12.2	1.9	13.5	0.6
Mole Flow lbmol/hr	140602.4	1011.5	527.4	527.4	1478.3	212.1	1779.5	46.5
Enthalpy MMBtu/hr	-8095.5	-87.5	-0.7	-0.2	-111.8	-0.7	-129.9	-6.9
Substream: MIXED								
Cp Btu/lb-R	0.303	0.248	0.243	0.244	0.282		0.359	0.207

Appendix B

Cost of Electricity (COE) Analysis

Cost of Electricity Analysis

The cost of electricity was evaluated using data from the EG&G Cost Estimating notebook (version 1.11) and several contractor reports. The format follows the guidelines set by EPRI TAG. The individual section costs for each case are listed in the following COE spreadsheet summarizies and are based on capacity-factored techniques. All costs are reported in 1st Quarter 2002 dollars.
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Bulk Plant Items

Bulk plant items include water systems, civil/structural/architectural, piping, control and instrumentation, and electrical systems. These were calculated based on a percentage of the total installed equipment costs. The percentages in parenthesis, for coal systems, are for the hot-gas cleanup process, which has a lower water requirement, and therefore, a smaller percentage for piping and water systems. The following percentages were used in this report.

	% of Installed Equipment Cost		
Plant Type :	**Natural Gas**	**PC Plant**	**Coal**
Bulk Plant Item			
Water Systems	7.1	6.3	5.5 (3.5)
Civil/Structural/Architectural	13.9	10.0	6.2
Piping	7.1	6.3	5.5 (3.5)
Control and Instrumentation	8.0	6.0	4.0
Electrical Systems	15.8	12.2	8.7
Total	51.9	40.8	29.9 (25.9)

Table 1, Table 2, and Table 3 show the assumptions used in this COE analysis.

Table 1. Capital Cost Assumptions

Engineering Fee	10% of PPC*
Project Contingency	15% of PPC
Construction Period	4 Yrs (coal), 2 Yrs (NG)
Inflation Rate	3%
Discount Rate	11.2%
Prepaid Royalties	0.5% of PPC
Catalyst and Chemical Inventory	30 Dys
Spare Parts	0.5% of TPC**
Land	200 Acres @ $6,500/Acre
<u>Start-Up Costs</u>	
Plant Modifications	2% of TPI***
Operating Costs	30 Dys
Fuel Costs	7.5 Dys
<u>Working Capital</u>	
Coal	60 Dys
By-Product Inventory	30 Dys
O&M Costs	30 Dys

* PPC = Process Plant Cost
** TPC = Total Plant Cost
*** TPI = Total Plant Investment

Table 2. Operating & Maintenance Assumptions

Consumable Material Prices	
Illinois #6 Coal	$24.36/Ton
Natural Gas	$3.20 / 1000 SCF
Raw Water	$0.19 /Ton
MDEA Solvent	$1.45/Lb
Claus Catalyst	$470/Ton
SCOT Activated Alumina	$0.067/Lb
Sorbent	$6,000/Ton
Nahcolite	$275/Ton
Limestone (FGD)	$16/Ton
Off-Site Ash/Sorbent Disposal Costs	$8.00/Ton
Operating Royalties	1% of Fuel Cost
Operator Labor	$34.00/hour
Number of Shifts for Continuous Operation	4.2
Supervision and Clerical Labor	30% of O&M Labor
Maintenance Costs	2.2% of TPC
Insurance and Local Taxes	2% of TPC
Miscellaneous Operating Costs	10% of O&M Labor
Capacity Factor	85%

Table 3. Investment Factor Economic Assumptions

Annual Inflation Rate			3%
Real Escalation Rate (over inflation)			
O&M			0%
Coal			-1.1%
Natural Gas			0.2%
Discount Rate			11.2%
Debt	80% of Total	9.0% Cost	7.2% Return
Preferred Stock	0% of Total	0.0% Cost	0% Return
Common Stock	20% of Total	20.0% Cost	4.0% Return
			11.2% Total
Book Life			20 Yrs
Tax Life			20 Yrs
State and Federal Tax Rate			38%
Investment Tax Credit			0%
Number of Years Levelized Cost			10 Yrs

Cost of Electricity (COE) Spreadsheet Listings

Pulverized Coal (PC)

PC Steam Cycle – No CO_2 Capture

PULIVERIZED COAL (PC) PLANT 397 MW POWER PLANT

1st Q 2002 Dollar

Total Plant Investment AREA NO	PLANT SECTION DESCRIPTION	PROCESS CONT, %	PROCESS CONT, K$	COST, K$ W/O CONT
11	Coal Preparation & Feed	0	$0	$17,617
12	PC Boiler, Fans & Accessories	0	$0	$75,094
13	Flue Gas Cleanup (Precipitator,FGD)	0	$0	$56,290
13	Sorbent Preparation & Handling	0	$0	$6,002
13	Stack / Ductwork	0	$0	$18,816
15	Steam Turbine & Accessories	0	$0	$59,088
14	Spent Sorbent/Ash disposal system	0	$0	$18,273
18	Water Systems	0	$0	$15,824
30	Civil/Structural/Architectural	0	$0	$25,118
40	Piping	0	$0	$15,824
50	Control/ Instrumentation	0	$0	$15,071
60	Electrical	0	$0	$30,644

Subtotal, Process Plant Cost		$353,660
Engineering Fees		$35,366
Process Contingency (Using cont. listed)		$0
Project Contingency,	15 % Proc Plt & Gen Plt Fac	$53,049
Total Plant Cost (TPC)		$442,075
Plant Construction Period,	3.0 Years (1 or more)	
Construction Interest Rate,	11.2 %	
Adjustment for Interest and Inflation		$36,030
Total Plant Investment (TPI)		$478,105
Prepaid Royalties		$1,768
Initial Catalyst and Chemical Inventory		$333
Startup Costs		$12,273
Spare Parts		$2,210
Working Capital		$7,103
Land,	200 Acres	$1,300
Total Capital Requirement (TCR)		$503,092
	$/kW	1268

ANNUAL OPERATING COSTS

Capacity Factor = 85 %

COST ITEM		QUANTITY		UNIT $ PRICE		ANNUAL COST, K$
Coal (Illinois #6)		3714	T/D	$24.36	/T	$28,066
Consumable Materials						
Water		38,160	T/D	$0.19	/T	$2,249
Limestone		363.0	T/D	$16.00	/T	$1,802
Ash/Sorbent Disposal Costs		739	T/D	$8.00	/T	$1,835
Plant Labor						
Oper Labor (incl benef)		15	Men/shift	$34.00	/Hr.	$4,455
Supervision & Clerical						$2,504
Maintenance Costs	2.2%					$9,726
Royalties						$281
Other Operating Costs						$835
Total Operating Costs						$51,752
By-Product Credits						
		0.0	T/D	$0.00	/T	$0
		0.0	T/D	$0.00	/T	$0
Total By-Product Credits						$0
Net Operating Costs						$51,752

BASES AND ASSUMPTIONS

A. CAPITAL BASES AND DETAILS

	QUANTITY	UNIT $ PRICE	COST, K$
Initial Cat./Chem. Inventory			
Water	973080 T	$0.19 /T	$185
Limestone	9257 T	$16.00 /T	$148
Total Catalyst and Chemical Inventory			$333
Startup costs			
Plant modifications,	2 % TPI		$9,562
Operating costs			$2,032
Fuel			$678
Total Startup Costs			$12,273
Working capital			
Fuel & Consumables inv	60 days supply		$6,211
By-Product inventory	30 days supply		$0
Direct expenses	30 days		$892
Total Working Capital			$7,103

B. ECONOMIC ASSUMPTIONS

Project life	20 Years
Book life	20 Years
Tax life	20 Years
Federal and state income tax rate	38.0 %
Tax depreciation method	ACRS
Investment Tax Credit	0.0 %

Financial structure

Type of Security	% of Total	Current Dollar Cost, %	Current Dollar Ret, %	Constant Dollar Cost, %	Constant Dollar Ret, %
Debt	80	9.0	7.2	5.8	4.6
Preferred Stock	0	3.0	0.0	0.0	0.0
Common Stock	20	20.0	4.0	16.5	3.3
Discount rate (cost of capital)			11.2		7.9

Inflation rate, % per year	3.0
Real Escalation rates (over inflation)	
Fuel, % per year	-1.1
Operating & Maintenance, % per year	0.0

C. COST OF ELECTRICITY

The approach to determining the cost of electricity is based upon the methodology described in the Technical Assessment Guide, published by the Electric Power Research Institute. The cost of electricity is stated in terms of 10th year levelized dollars.

Levelizing Factors	Current $	Constant $
Capital Carrying Charge, 10th yr	0.179	0.148
Fuel, 10th year	1.091	0.948
Operating & Maintenance, 10th yr	1.151	1.000

Cost of Electricity - Levelized	mills/kWh	mills/kWh
Capital Charges	30.5	25.3
Fuel Costs	10.4	9.0
Consumables	2.3	2.0
Fixed Operating & Maintenance	5.9	5.1
Variable Operating & Maintenance	1.0	0.9
By-product	0.0	0.0
Total Cost of Electricity	50.1	42.3

Pulverized Coal (PC)

PC Steam Cycle - Amine CO_2 Capture

PULIVERIZED COAL (PC) PLANT 283 MW POWER PLANT

AMINE CASE 1st Q 2002 Dollar

Total Plant Investment

AREA NO	PLANT SECTION DESCRIPTION	PROCESS CONT, %	PROCESS CONT, K$	COST, K$ W/O CONT
11	Coal Preparation & Feed	0	$0	$17,617
12	PC Boiler, Fans & Accessories	0	$0	$75,094
13	Flue Gas Cleanup (Precipitator,FGD)	0	$0	$56,290
13	Sorbent Preparation & Handling	0	$0	$6,002
13	Stack / Ductwork	0	$0	$15,664
15	Steam Turbine & Accessories	0	$0	$50,898
14	Spent Sorbent/Ash disposal system	0	$0	$18,273
15	Amine Plant	0	$0	$92,423
16	CO2 Compression	0	$0	$30,103
18	Water Systems	0	$0	$17,006
30	Civil/Structural/Architectural	0	$0	$26,994
40	Piping	0	$0	$17,006
50	Control/ Instrumentation	0	$0	$16,196
60	Electrical	0	$0	$32,933

Subtotal, Process Plant Cost		$472,500
Engineering Fees		$47,250
Process Contingency (Using cont. listed)		$0
Project Contingency,	15 % Proc Plt & Gen Plt Fac	$70,875
Total Plant Cost (TPC)		$590,625
Plant Construction Period,	3.0 Years (1 or more)	
Construction Interest Rate,	11.2 %	
Adjustment for Interest and Inflation		$48,137
Total Plant Investment (TPI)		$638,761
Prepaid Royalties		$2,362
Initial Catalyst and Chemical Inventory		$969
Startup Costs		$16,538
Spare Parts		$2,953
Working Capital		$8,739
Land, 200 Acres		$1,300
Total Capital Requirement (TCR)		$671,624
	$/kW	2373

ANNUAL OPERATING COSTS

Capacity Factor = 85 %

COST ITEM	QUANTITY		UNIT $ PRICE		ANNUAL COST, K$
Coal (Illinois #6)	3714	T/D	$24.36	/T	$28,066
Consumable Materials					
Water	38,160	T/D	$0.19	/T	$2,249
Limestone	363	T/D	$16.00	/T	$1,802
Amine Chemicals	8,315	T/D	$3.00	/T CO2 captur	$7,739
Ash/Sorbent Disposal Costs	707	T/D	$8.00	/T	$1,756
Plant Labor					
Oper Labor (incl benef)	15	Men/shift	$34.00	/Hr.	$4,455
Supervision & Clerical					$2,896
Maintenance Costs	2.2%				$12,994
Royalties					$281
Other Operating Costs					$965
Total Operating Costs					$63,203
By-Product Credits					
	0.0	T/D	$0.00	/T	$0
	0.0	T/D	$0.00	/T	$0
Total By-Product Credits					$0
Net Operating Costs					$63,203

BASES AND ASSUMPTIONS

A. CAPITAL BASES AND DETAILS

	QUANTITY		UNIT $ PRICE		COST, K$
Initial Cat./Chem. Inventory					
Water	973080	T	$0.19	/T	$185
Limestone	9257	T	$16.00	/T	$148
Amine Chemicals	212033	T	$3.00	/T	$636
Total Catalyst and Chemical Inventory					$969
Startup costs					
Plant modifications,	2	% TPI			$12,775
Operating costs					$3,084
Fuel					$678
Total Startup Costs					$16,538
Working capital					
Fuel & Consumables inv	60	days supply			$7,708
By-Product inventory	30	days supply			$0
Direct expenses	30	days			$1,031
Total Working Capital					$8,739

B. ECONOMIC ASSUMPTIONS

Project life	20	Years
Book life	20	Years
Tax life	20	Years
Federal and state income tax rate	38.0	%
Tax depreciation method	ACRS	
Investment Tax Credit	0.0	%

Financial structure

Type of Security	% of Total	Current Dollar Cost, %	Current Dollar Ret, %	Constant Dollar Cost, %	Constant Dollar Ret, %
Debt	80	9.0	7.2	5.8	4.6
Preferred Stock	0	3.0	0.0	0.0	0.0
Common Stock	20	20.0	4.0	16.5	3.3
Discount rate (cost of capital)			11.2		7.9

Inflation rate, % per year	3.0
Real Escalation rates (over inflation)	
Fuel, % per year	-1.1
Operating & Maintenance, % per year	0.0

C. COST OF ELECTRICITY

The approach to determining the cost of electricity is based upon the methodology described in the Technical Assessment Guide, published by the Electric Power Research Institute. The cost of electricity is stated in terms of 10th year levelized dollars.

Levelizing Factors	Current $	Constant $
Capital Carrying Charge, 10th yr	0.179	0.148
Fuel, 10th year	1.091	0.948
Operating & Maintenance, 10th yr	1.151	1.000

Cost of Electricity - Levelized	mills/kWh	mills/kWh
Capital Charges	57.1	47.3
Fuel Costs	14.5	12.6
Consumables	7.4	6.4
Fixed Operating & Maintenance	10.0	8.7
Variable Operating & Maintenance	1.8	1.5
By-product	0.0	0.0
Total Cost of Electricity	90.8	76.6

Pulverized Coal (PC)

PC Steam Cycle - O_2 Boiler / CO_2 Capture

PULIVERIZED COAL (PC) PLANT — 298 MW POWER PLANT

CRYOGENIC CASE — 1st Q 2002 Dollar

Total Plant Investment

AREA NO	PLANT SECTION DESCRIPTION	PROCESS CONT, %	PROCESS CONT, K$	COST, K$ W/O CONT
11	Coal Preparation & Feed	0	$0	$17,118
12	PC Boiler, Fans & Accessories	0	$0	$72,808
13	Flue Gas Cleanup (Precipitator,FGD)	0	$0	$51,632
13	Sorbent Preparation & Handling	0	$0	$6,002
13	Stack / Ductwork	0	$0	$1,009
15	Steam Turbine & Accessories	0	$0	$58,828
14	Spent Sorbent/Ash disposal system	0	$0	$17,882
15	Oxygen Plant	0	$0	$111,099
16	CO2 Compression	0	$0	$34,208
18	Water Systems	0	$0	$16,348
30	Civil/Structural/Architectural	0	$0	$25,949
40	Piping	0	$0	$16,348
50	Control/ Instrumentation	0	$0	$15,569
60	Electrical	0	$0	$31,657

Subtotal, Process Plant Cost		$476,456
Engineering Fees		$47,646
Process Contingency (Using cont. listed)		$0
Project Contingency,	15 % Proc Plt & Gen Plt Fac	$71,468
Total Plant Cost (TPC)		$595,570
Plant Construction Period,	3.0 Years (1 or more)	
Construction Interest Rate,	11.2 %	
Adjustment for Interest and Inflation		$48,540
Total Plant Investment (TPI)		$644,110
Prepaid Royalties		$2,382
Initial Catalyst and Chemical Inventory		$327
Startup Costs		$15,869
Spare Parts		$2,978
Working Capital		$6,998
Land, 200 Acres		$1,300
Total Capital Requirement (TCR)		$673,964
	$/kW	2259

ANNUAL OPERATING COSTS

Capacity Factor = 85 %

COST ITEM	QUANTITY		UNIT $ PRICE		ANNUAL COST, K$
Coal (Illinois #6)	3553	T/D	$24.36	/T	$26,854
Consumable Materials					
Water	38,160	T/D	$0.19	/T	$2,249
Limestone	347	T/D	$16.00	/T	$1,724
Ash/Sorbent Disposal Costs	707	T/D	$8.00	/T	$1,756
Plant Labor					
Oper Labor (incl benef)	15	Men/shift	$34.00	/Hr.	$4,455
Supervision & Clerical					$2,909
Maintenance Costs 2.2%					$13,103
Royalties					$269
Other Operating Costs					$970
Total Operating Costs					$54,288
By-Product Credits					
	0.0	T/D	$0.00	/T	$0
	0.0	T/D	$0.00	/T	$0
Total By-Product Credits					$0
Net Operating Costs					$54,288

BASES AND ASSUMPTIONS

A. CAPITAL BASES AND DETAILS

	QUANTITY		UNIT $ PRICE		COST, K$
Initial Cat./Chem. Inventory					
Water	973080	T	$0.19	/T	$185
Limestone	8858	T	$16.00	T	$142
Total Catalyst and Chemical Inventory					$327
Startup costs					
Plant modifications,	2	% TPI			$12,882
Operating costs					$2,338
Fuel					$649
Total Startup Costs					$15,869
Working capital					
Fuel & Consumables inv	60	days supply			$5,962
By-Product inventory	30	days supply			$0
Direct expenses	30	days			$1,036
Total Working Capital					$6,998

B. ECONOMIC ASSUMPTIONS

Project life	20	Years
Book life	20	Years
Tax life	20	Years
Federal and state income tax rate	38.0	%
Tax depreciation method	ACRS	
Investment Tax Credit	0.0	%

Financial structure

Type of Security	% of Total	Current Dollar Cost, %	Current Dollar Ret, %	Constant Dollar Cost, %	Constant Dollar Ret, %
Debt	80	9.0	7.2	5.8	4.6
Preferred Stock	0	3.0	0.0	0.0	0.0
Common Stock	20	20.0	4.0	16.5	3.3
Discount rate (cost of capital)			11.2		7.9

Inflation rate, % per year	3.0
Real Escalation rates (over inflation)	
Fuel, % per year	-1.1
Operating & Maintenance, % per year	0.0

C. COST OF ELECTRICITY

The approach to determining the cost of electricity is based upon the methodology described in the Technical Assessment Guide, published by the Electric Power Research Institute. The cost of electricity is stated in terms of 10th year levelized dollars.

Levelizing Factors	Current $	Constant $
Capital Carrying Charge, 10th yr	0.179	0.148
Fuel, 10th year	1.091	0.948
Operating & Maintenance, 10th yr	1.151	1.000

Cost of Electricity - Levelized	mills/kWh	mills/kWh
Capital Charges	54.3	45.0
Fuel Costs	13.2	11.5
Consumables	3.0	2.6
Fixed Operating & Maintenance	9.6	8.3
Variable Operating & Maintenance	1.7	1.5
By-product	0.0	0.0
Total Cost of Electricity	81.7	68.8

Combined Cycle

Natural Gas Combined Cycle (NGCC) - No CO_2 Capture

Natural Gas Combined Cycle			**379**	**MW POWER PLANT**	
W501G					1st Q 2002 Dollar
Total Plant Investment			PROCESS	PROCESS	COST, K$
AREA NO	PLANT SECTION DESCRIPTION		CONT, %	CONT, K$	W/O CONT
15	Gas Turbine		5	$2,619	$52,388
15	Steam Cycle		5	$2,103	$42,065
18	Water Systems		0		$6,706
30	Civil/Structural/Architectural		0		$13,129
40	Piping		0		$6,706
50	Control/ Instrumentation		0		$7,556
60	Electrical		0		$14,924
	Subtotal, Process Plant Cost				$128,551
Engineering Fees					$12,855
Process Contingency (Using cont. listed)					$4,723
Project Contingency,		15 % Proc Plt & Gen Plt Fac			$19,283
	Total Plant Cost (TPC)				$165,412
				$/kw	$436
Plant Construction Period,		2.0 Years (1 or more)			
Construction Interest Rate,		11.2 %			
Adjustment for Interest and Inflation					$6,567
	Total Plant Investment (TPI)				$171,979
Prepaid Royalties					$643
Initial Catalyst and Chemical Inventory					$5
Startup Costs					$9,925
Spare Parts					$827
Working Capital					$11,705
Land,	100 Acres	@ $1500/acre			$150
	Total Capital Requirement (TCR)				$195,233
			$/kW		515

ANNUAL OPERATING COSTS

Capacity Factor = 85 %

Consumables COST ITEM		QUANTITY		UNIT $ PRICE		ANNUAL COST, K$
Natural Gas		58,760	1000 SCF/day	$3.20	/1000 SCF	$58,337
Water		2,263	1000 gal/day	$0.80	/1000 gal	$562
Plant Labor						
Oper Labor (incl benef)		5	Men/shift	$34.00	/Hr.	$1,485
Supervision & Clerical						$882
Maintenance Costs	2.2%					$3,639
Insurance & Local Taxes						$3,308
Other Operating Costs						$294
Total Operating Costs						$68,507

BASES AND ASSUMPTIONS

A. CAPITAL BASES AND DETAILS

	QUANTITY		UNIT $ PRICE		COST, K$
Initial Cat./Chem. Inventory					
Water	5,771	1000 gallons	$0.80	/1000 gal	$5
Total Catalyst and Chemical Inventory					$5
Startup costs					
Plant modifications,	2	% TPI			$3,440
Operating costs					$6,485
Total Startup Costs					$9,925
Working capital					
Fuel & Consumables inv	60	days supply			$11,391
Direct expenses	30	days			$314
Total Working Capital					$11,705

B. ECONOMIC ASSUMPTIONS

Project life	20	Years
Book life	20	Years
Tax life	20	Years
Federal and state income tax rate	38.0	%
Tax depreciation method	MACRS	
Investment Tax Credit	0.0	%

Financial structure

Type of Security	% of Total	Current Dollar Cost, %	Current Dollar Ret, %	Constant Dollar Cost, %	Constant Dollar Ret, %
Debt	80	9.0	7.2	5.8	4.6
Preferred Stock	0	0.0	0.0	0.0	0.0
Common Stock	20	20.0	4.0	16.5	3.3
Discount rate (cost of capital)			11.2		7.9

Inflation rate, % per year	3.0
Real Escalation rates (over inflation)	
Fuel, % per year	0.2
Operating & Maintenance, % per year	0.0

C. COST OF ELECTRICITY

The approach to determining the cost of electricity is based upon the methodology described in the Technical Assessment Guide, published by the Electric Power Research Institute. The cost of electricity is stated in terms of 10th year levelized dollars.

Levelizing Factors	Current $	Constant $
Capital Carrying Charge, 10th yr	0.179	0.148
Fuel, 10th year	1.162	1.010
Operating & Maintenance, 10th yr	1.151	1.000

Cost of Electricity - Levelized	mills/kWh	mills/kWh
Capital Charges	12.4	10.3
Fuel Costs	24.0	20.9
Consumables	0.2	0.2
Fixed Operating & Maintenance	3.3	2.9
Variable Operating & Maintenance	0.6	0.5
By-product	0.0	0.0
Total Cost of Electricity	40.5	34.7

Combined Cycle

Natural Gas Combined Cycle (NGCC) - CO_2 Capture

Natural Gas Combined Cycle			**327 MW POWER PLANT**	
W501G + CO2 CAPTURE				1st Q 2002 Dollar
Total Plant Investment		PROCESS	PROCESS	COST, K$
AREA NO	PLANT SECTION DESCRIPTION	CONT, %	CONT, K$	W/O CONT
15	Gas Turbine	5	$2,619	$52,389
15	Steam Cycle	5	$1,872	$37,438
20	Amine System	5	$3,453	$69,053
20	CO2 Compression/drying	5	$526	$10,530
18	Water Systems	0		$6,378
30	Civil/Structural/Architectural	0		$12,486
40	Piping	0		$6,378
50	Control/ Instrumentation	0		$7,186
60	Electrical	0		$14,193
	Subtotal, Process Plant Cost			$201,836
Engineering Fees				$20,184
Process Contingency (Using cont. listed)				$8,470
Project Contingency,	15 % Proc Plt & Gen Plt Fac			$30,275
	Total Plant Cost (TPC)			$260,765
			$/kw	$798
Plant Construction Period,	2.0 Years (1 or more)			
Construction Interest Rate,	11.2 %			
Adjustment for Interest and Inflation				$10,352
	Total Plant Investment (TPI)			$271,117
Prepaid Royalties				$1,009
Initial Catalyst and Chemical Inventory				$5
Startup Costs				$12,264
Spare Parts				$1,304
Working Capital				$11,794
Land,	100 Acres @ $1500/acre			$150
	Total Capital Requirement (TCR)			$297,643
		$/kW		911

ANNUAL OPERATING COSTS

Capacity Factor = 85 %

Consumables COST ITEM	QUANTITY		UNIT $ PRICE		ANNUAL COST, K$
Natural Gas	58,760	1000 SCF/da	$3.20	/1000 SCF	$58,337
Water	2,263	1000 gal/day	$0.80	/1000 gallons	$562
Amine Chemicals	130	ton CO2/hr	$3.00	/ton CO2 Capt	$2,893
Plant Labor					
Oper Labor (incl benef)	5	Men/shift	$34.00	/Hr.	$1,485
Supervision & Clerical					$1,134
Maintenance Costs 2.2%					$5,737
Insurance & Local Taxes					$5,215
Other Operating Costs					$378
Total Operating Costs					$72,848

BASES AND ASSUMPTIONS

A. CAPITAL BASES AND DETAILS

	QUANTITY		UNIT $ PRICE		COST, K$
Initial Cat./Chem. Inventory					
Water	5,771	1000 gallons	$0.80	/1000 gallons	$5
Amine Chemicals	18,492	(7 days CO2)	$3.00	/ton CO2	$55
Total Catalyst and Chemical Inventory					$5
Startup costs					
Plant modifications,	2	% TPI			$5,422
Operating costs					$6,842
Total Startup Costs					$12,264
Working capital					
Fuel & Consumables inv	60	days supply			$11,391
Direct expenses	30	days			$404
Total Working Capital					$11,794

B. ECONOMIC ASSUMPTIONS

Project life	20	Years
Book life	20	Years
Tax life	20	Years
Federal and state income tax rate	38.0	%
Tax depreciation method	MACRS	
Investment Tax Credit	0.0	%

Financial structure

Type of Security	% of Total	Current Dollar Cost, %	Current Dollar Ret, %	Constant Dollar Cost, %	Constant Dollar Ret, %
Debt	80	9.0	7.2	5.8	4.6
Preferred Stock	0	0.0	0.0	0.0	0.0
Common Stock	20	20.0	4.0	16.5	3.3
Discount rate (cost of capital)			11.2		7.9

Inflation rate, % per year	3.0
Real Escalation rates (over inflation)	
Fuel, % per year	0.2
Operating & Maintenance, % per year	0.0

C. COST OF ELECTRICITY

The approach to determining the cost of electricity is based upon the methodology described in the Technical Assessment Guide, published by the Electric Power Research Institute. The cost of electricity is stated in terms of 10th year levelized dollars.

	Current $	Constant $
Levelizing Factors		
Capital Carrying Charge, 10th yr	0.179	0.148
Fuel, 10th year	1.162	1.010
Operating & Maintenance, 10th yr	1.151	1.000

Cost of Electricity - Levelized	mills/kWh	mills/kWh
Capital Charges	21.9	18.2
Fuel Costs	27.9	24.2
Consumables	0.3	0.2
Fixed Operating & Maintenance	5.6	4.9
Variable Operating & Maintenance	1.0	0.9
By-product	0.0	0.0
Total Cost of Electricity	56.6	48.3

Combined Cycle

IGCC Destec (E-Gas^{TM}) / CGCU / “G” Gas Turbine

Destec CGCU IGCC **401 MW POWER PLANT**

1st Q 2002 Dollar

Total Plant Investment

AREA NO	PLANT SECTION DESCRIPTION	PROCESS CONT, %	PROCESS CONT, K$	COST, K$ W/O CONT
11	Coal Slurry Preparation	0	$0	$27,007
12	Oxygen Plant	0	$0	$49,777
12	Destec Gasifier	5	$3,144	$62,876
12	Recycle Gas Compressor	5	$135	$2,696
14	Low Temperature Gas Cooling	0	$0	$13,986
14	MDEA	0	$0	$5,298
14	Claus	0	$0	$10,129
14	SCOT	0	$0	$4,284
15	Gas Turbine System	5	$2,871	$57,410
15	HRSG/Steam Turbine	5	$2,463	$49,269
18	Water Systems	0	$0	$15,550
30	Civil/Structural/Architectural	0	$0	$17,529
40	Piping	0	$0	$15,550
50	Control/ Instrumentation	0	$0	$11,309
60	Electrical	0	$0	$24,598

Subtotal, Process Plant Cost		$367,266
Engineering Fees		$36,727
Process Contingency (Using cont. listed)		$8,613
Project Contingency,	15 % Proc Plt & Gen Plt Fac	$55,090
Total Plant Cost (TPC)		$467,695
Plant Construction Period,	4.0 Years (1 or more)	
Construction Interest Rate,	11.2 %	
Adjustment for Interest and Inflation		$58,710
Total Plant Investment (TPI)		$526,405
Prepaid Royalties		$1,836
Initial Catalyst and Chemical Inventory		$69
Startup Costs		$12,745
Spare Parts		$2,338
Working Capital		$5,719
Land, 200 Acres		$1,300
Total Capital Requirement (TCR)		$550,414
	$/kW	1374

ANNUAL OPERATING COSTS

Capacity Factor = 85 %

COST ITEM	QUANTITY		UNIT $ PRICE		ANNUAL COST, K$
Coal (Illinois #6)	3,123	T/D	$24.36	/T	$23,600
Consumable Materials					
Water	2,924	T/D	$0.19	/T	$172
MDEA Solvent	403.2	Lb/D	$1.45	/Lb	$181
Claus Catalyst	0.01	T/D	$470	/T	$1
SCOT Activated Alumin	15.9	Lb/D	$0.67	/Lb	$3
SCOT Cobalt Catalyst					$5
SCOT Chemicals					$16
Ash/Sorbent Disposal Costs	413	T/D	$8.00	/T	$1,024
Plant Labor					
Oper Labor (incl benef)	15	Men/shift	$34.00	/Hr.	$4,455
Supervision & Clerical					$2,571
Maintenance Costs 2.2%					$10,289
Royalties					$236
Other Operating Costs					$857
Total Operating Costs					$43,412
By-Product Credits					
Sulfur	75.5	T/D	$75.00	/T	$1,757
	0.0	T/D	$0.00	/T	$0
Total By-Product Credits					$1,757
Net Operating Costs					$41,655

BASES AND ASSUMPTIONS

A. CAPITAL BASES AND DETAILS

	QUANTITY		UNIT $ PRICE		COST, K$
Initial Cat./Chem. Inventory					
Water	74550	T	$0.19	/T	$14
MDEA Solvent	10282	Lb	$1.45	/Lb	$15
Claus Catalyst	0.3	T	$470	/T	$0
SCOT Activated Alumin	405	Lb	$0.67	/Lb	$0
SCOT Cobalt Catalyst					$16
SCOT Chemicals					$24
Total Catalyst and Chemical Inventory					$69
Startup costs					
Plant modifications,	2	% TPI			$10,528
Operating costs					$1,647
Fuel					$570
Total Startup Costs					$12,745
Working capital					
Fuel & Consumables inv	60	days supply			$4,633
By-Product inventory	30	days supply			$170
Direct expenses	30	days			$916
Total Working Capital					$5,719

B. ECONOMIC ASSUMPTIONS

Project life	20	Years
Book life	20	Years
Tax life	20	Years
Federal and state income tax rate	38.0	%
Tax depreciation method	MACRS	
Investment Tax Credit	0.0	%

Financial structure

Type of Security	% of Total	Current Dollar Cost, %	Current Dollar Ret, %	Constant Dollar Cost, %	Constant Dollar Ret, %
Debt	80	9.0	7.2	5.8	4.6
Preferred Stock	0	3.0	0.0	0.0	0.0
Common Stock	20	20.0	4.0	16.5	3.3
Discount rate (cost of capital)			11.2		7.9

Inflation rate, % per year	3.0
Real Escalation rates (over inflation)	
Fuel, % per year	-1.1
Operating & Maintenance, % per year	0.0

C. COST OF ELECTRICITY

The approach to determining the cost of electricity is based upon the methodology described in the Technical Assessment Guide, published by the Electric Power Research Institute. The cost of electricity is stated in terms of 10th year levelized dollars.

Levelizing Factors	Current $	Constant $
Capital Carrying Charge, 10th yr	0.179	0.148
Fuel, 10th year	1.091	0.948
Operating & Maintenance, 10th yr	1.151	1.000

Cost of Electricity - Levelized	mills/kWh	mills/kWh
Capital Charges	33.0	27.4
Fuel Costs	8.6	7.5
Consumables	0.5	0.5
Fixed Operating & Maintenance	6.0	5.2
Variable Operating & Maintenance	1.1	0.9
By-product	-0.7	-0.6
Total Cost of Electricity	48.6	40.9

Combined Cycle

IGCC Destec (E-Gas^{TM}) / HGCU / “G” Gas Turbine

Destec HGCU IGCC **400 MW POWER PLANT**

1st Q 2002 Dollar

Total Plant Investment AREA NO	 PLANT SECTION DESCRIPTION	PROCESS CONT, %	PROCESS CONT, K$	COST, K$ W/O CONT
11	Coal Slurry Preparation	0	$0	$25,914
12	Oxygen Plant	0	$0	$46,751
12	Destec Gasifier	5	$2,853	$57,054
12	Gas Compression (Recycle and Quench)	5	$275	$5,491
14	Gas Conditioning	10	$1,532	$15,321
14	Air Boost Compressor	0	$0	$882
14	Transport Desulfurizer	15	$1,322	$8,815
14	Sulfuric Acid Plant	0	$0	$18,554
15	Gas Turbine System	5	$2,868	$57,368
15	HRSG/Steam Turbine	5	$2,454	$49,082
18	Water Systems	0	$0	$9,983
30	Civil/Structural/Architectural	0	$0	$17,684
40	Piping	0	$0	$9,983
50	Control/ Instrumentation	0	$0	$11,409
60	Electrical	0	$0	$24,815

Subtotal, Process Plant Cost		$359,109
Engineering Fees		$35,911
Process Contingency (Using cont. listed)		$11,304
Project Contingency,	15 % Proc Plt & Gen Plt Fac	$53,866
Total Plant Cost (TPC)		$460,191
Plant Construction Period,	4.0 Years (1 or more)	
Construction Interest Rate,	11.2 %	
Adjustment for Interest and Inflation		$57,768
Total Plant Investment (TPI)		$517,958
Prepaid Royalties		$1,796
Initial Catalyst and Chemical Inventory		$302
Startup Costs		$12,548
Spare Parts		$2,301
Working Capital		$5,768
Land,	200 Acres	$1,300
Total Capital Requirement (TCR)		$541,973
	$/kW	1354

ANNUAL OPERATING COSTS

Capacity Factor = 85 %

COST ITEM	QUANTITY		UNIT $ PRICE		ANNUAL COST, K$
Coal (Illinois #6)	2,944	T/D	$24.36	/T	$22,247
Consumable Materials					
Water	2,102	T/D	$0.19	/T	$124
HGCU Sorbent	0.11	T/D	$6,000	/T	$197
Nahcolite	2.3	T/D	$275	/T	$196
Ash/Sorbent Disposal Costs	436	T/D	$8.00	/T	$1,082
Plant Labor					
Oper Labor (incl benef)	15	Men/shift	$34.00	/Hr.	$4,455
Supervision & Clerical					$2,552
Maintenance Costs 2.2%					$10,124
Royalties					$222
Other Operating Costs					$851
Total Operating Costs					$42,050
By-Product Credits					
Sulfuric Acid	223.8	T/D	$68.00	/T	$4,722
___________________	0.0	T/D	$0.00	/T	$0
___________________	0.0	T/D	$0.00	/T	$0
___________________	0.0	T/D	$0.00	/T	$0
Total By-Product Credits					$4,722
Net Operating Costs					$37,328

BASES AND ASSUMPTIONS

A. CAPITAL BASES AND DETAILS

	QUANTITY	UNIT $ PRICE	COST, K$
Initial Cat./Chem. Inventory			
Water	53594 T	$0.19 /T	$10
HGCU Sorbent	46 T	$6,000 /T	$276
Nahcolite	59 T	$275 /T	$16
Total Catalyst and Chemical Inventory			$302
Startup costs			
Plant modifications,	2 % TPI		$10,359
Operating costs			$1,651
Fuel			$538
Total Startup Costs			$12,548
Working capital			
Fuel & Consumables inv	60 days supply		$4,402
By-Product inventory	30 days supply		$457
Direct expenses	30 days		$909
Total Working Capital			$5,768

B. ECONOMIC ASSUMPTIONS

Project life	20 Years
Book life	20 Years
Tax life	20 Years
Federal and state income tax rate	38.0 %
Tax depreciation method	MACRS
Investment Tax Credit	0.0 %

Financial structure

Type of Security	% of Total	Current Dollar Cost, %	Current Dollar Ret, %	Constant Dollar Cost, %	Constant Dollar Ret, %
Debt	80	9.0	7.2	5.8	4.6
Preferred Stock	0	3.0	0.0	0.0	0.0
Common Stock	20	20.0	4.0	16.5	3.3
Discount rate (cost of capital)			11.2		7.9

Inflation rate, % per year	3.0
Real Escalation rates (over inflation)	
Fuel, % per year	-1.1
Operating & Maintenance, % per year	0.0

C. COST OF ELECTRICITY

The approach to determining the cost of electricity is based upon the methodology described in the Technical Assessment Guide, published by the Electric Power Research Institute. The cost of electricity is stated in terms of 10th year levelized dollars.

Levelizing Factors	Current $	Constant $
Capital Carrying Charge, 10th yr	0.179	0.148
Fuel, 10th year	1.091	0.948
Operating & Maintenance, 10th yr	1.151	1.000

Cost of Electricity - Levelized	mills/kWh	mills/kWh
Capital Charges	32.5	27.0
Fuel Costs	8.1	7.1
Consumables	0.6	0.5
Fixed Operating & Maintenance	6.0	5.2
Variable Operating & Maintenance	1.1	0.9
By-product	-1.8	-1.6
Total Cost of Electricity	46.5	39.1

Combined Cycle

IGCC Destec (E-Gas^{TM}) / CGCU /
"G" Gas Turbine / CO_2 Capture

Destec CGCU IGCC (with CO2 Capture) **359 MW POWER PLANT**

1st Q 2002 Dollar

Total Plant Investment AREA NO	 PLANT SECTION DESCRIPTION	PROCESS CONT, %	PROCESS CONT, K$	COST, K$ W/O CONT
11	Coal Slurry Preparation	0	$0	$27,807
12	Oxygen Plant	0	$0	$51,897
12	Destec Gasifier	5	$3,210	$64,202
12	Recycle Gas Compressor	5	$137	$2,750
14	Low Temperature Gas Cooling	0	$0	$15,834
14	Shift Reaction System	0	$0	$16,699
14	SELEXOL (H2S & CO2)	0	$0	$35,125
14	CO2 Compression/Recovery	0	$0	$19,893
14	Claus	0	$0	$9,942
14	SCOT	0	$0	$4,204
15	Gas Turbine System	5	$2,872	$57,448
15	HRSG/Steam Turbine	5	$2,291	$45,814
18	Water Systems	0	$0	$19,339
30	Civil/Structural/Architectural	0	$0	$21,800
40	Piping	0	$0	$19,339
50	Control/ Instrumentation	0	$0	$14,065
60	Electrical	0	$0	$30,590

Subtotal, Process Plant Cost		$456,747
Engineering Fees		$45,675
Process Contingency (Using cont. listed)		$8,511
Project Contingency,	15 % Proc Plt & Gen Plt Fac	$68,512
Total Plant Cost (TPC)		$579,445
Plant Construction Period,	4.0 Years (1 or more)	
Construction Interest Rate,	11.2 %	
Adjustment for Interest and Inflation		$72,737
Total Plant Investment (TPI)		$652,182
Prepaid Royalties		$2,284
Initial Catalyst and Chemical Inventory		$84
Startup Costs		$15,538
Spare Parts		$2,897
Working Capital		$6,062
Land, 200 Acres		$1,300
Total Capital Requirement (TCR)		$680,347
	$/kW	1897

ANNUAL OPERATING COSTS

Capacity Factor = 85 %

COST ITEM		QUANTITY		UNIT $ PRICE		ANNUAL COST, K$
Coal (Illinois #6)		3,256	T/D	$24.36	/T	$24,606
Consumable Materials						
Water		2,924	T/D	$0.19	/T	$172
Selexol Solvent		806.4	Lb/D	$1.45	/Lb	$363
Claus Catalyst		0.01	T/D	$470	/T	$1
SCOT Activated Alum		15.9	Lb/D	$0.67	/Lb	$3
SCOT Cobalt Catalyst						$5
SCOT Chemicals						$16
Ash/Sorbent Disposal Costs		413	T/D	$8.00	/T	$1,024
Plant Labor						
Oper Labor (incl benef)		15	Men/shift	$34.00	/Hr.	$4,455
Supervision & Clerical						$2,866
Maintenance Costs	2.2%					$12,748
Royalties						$246
Other Operating Costs						$955
Total Operating Costs						$47,461
By-Product Credits						
Sulfur		79.0	T/D	$75.00	/T	$1,838
___________________		0.0	T/D	$0.00	/T	$0
___________________		0.0	T/D	$0.00	/T	$0
___________________		0.0	T/D	$0.00	/T	$0
Total By-Product Credits						$1,838
Net Operating Costs						$45,624

BASES AND ASSUMPTIONS

A. CAPITAL BASES AND DETAILS

	QUANTITY		UNIT $ PRICE		COST, K$
Initial Cat./Chem. Inventory					
Water	74550	T	$0.19	/T	$14
Selexol Solvent	20563	Lb	$1.45	/Lb	$30
Claus Catalyst	0.3	T	$470	/T	$0
SCOT Activated Alum	405	Lb	$0.67	/Lb	$0
SCOT Cobalt Catalyst					$16
SCOT Chemicals					$24
Total Catalyst and Chemical Inventory					$84
Startup costs					
Plant modifications,	2	% TPI			$13,044
Operating costs					$1,900
Fuel					$595
Total Startup Costs					$15,538
Working capital					
Fuel & Consumables inv	60	days supply			$4,863
By-Product inventory	30	days supply			$178
Direct expenses	30	days			$1,021
Total Working Capital					$6,062

B. ECONOMIC ASSUMPTIONS

Project life	20	Years
Book life	20	Years
Tax life	20	Years
Federal and state income tax rate	38.0	%
Tax depreciation method	MACRS	
Investment Tax Credit	0.0	%

Financial structure

Type of Security	% of Total	Current Dollar Cost, %	Current Dollar Ret, %	Constant Dollar Cost, %	Constant Dollar Ret, %
Debt	80	9.0	7.2	5.8	4.6
Preferred Stock	0	3.0	0.0	0.0	0.0
Common Stock	20	20.0	4.0	16.5	3.3
Discount rate (cost of capital)			11.2		7.9

Inflation rate, % per year	3.0
Real Escalation rates (over inflation)	
Fuel, % per year	-1.1
Operating & Maintenance, % per year	0.0

C. COST OF ELECTRICITY

The approach to determining the cost of electricity is based upon the methodology described in the Technical Assessment Guide, published by the Electric Power Research Institute. The cost of electricity is stated in terms of 10th year levelized dollars.

	Current $	Constant $
Levelizing Factors		
Capital Carrying Charge, 10th yr	0.179	0.148
Fuel, 10th year	1.091	0.948
Operating & Maintenance, 10th yr	1.151	1.000

Cost of Electricity - Levelized	mills/kWh	mills/kWh
Capital Charges	45.6	37.8
Fuel Costs	10.1	8.7
Consumables	0.7	0.6
Fixed Operating & Maintenance	7.8	6.8
Variable Operating & Maintenance	1.4	1.2
By-product	-0.8	-0.7
Total Cost of Electricity	64.7	54.4

Combined Cycle

IGCC Shell / CGCU / “G” Gas Turbine

Shell CGCU IGCC Case 413 MW POWER PLANT

1st Q 2002 Dollar

Total Plant Investment AREA NO	PLANT SECTION DESCRIPTION	PROCESS CONT, %	PROCESS CONT, K$	COST, K$ W/O CONT
11	Coal Preparation	0	$0	$18,436
12	Oxygen Plant	0	$0	$52,564
12	Shell Gasifier	5	$4,041	$80,826
12	Quench Gas Compressor	5	$98	$1,951
14	Low Temperature Gas Cooling/Gas Saturation	0	$0	$9,606
14	MDEA	0	$0	$5,228
14	Claus	0	$0	$10,234
14	SCOT	0	$0	$4,328
15	Gas Turbine System	5	$2,755	$55,107
15	HRSG/Steam Turbine	5	$2,591	$51,828
18	Water Systems	0	$0	$15,956
30	Civil/Structural/Architectural	0	$0	$17,987
40	Piping	0	$0	$15,956
50	Control/ Instrumentation	0	$0	$11,604
60	Electrical	0	$0	$25,239

Subtotal, Process Plant Cost			$376,851
Engineering Fees			$37,685
Process Contingency (Using cont. listed)			$9,486
Project Contingency,	15	% Proc Plt & Gen Plt Fac	$56,528
Total Plant Cost (TPC)			$480,549
Plant Construction Period,	4.0	Years (1 or more)	
Construction Interest Rate,	11.2	%	
Adjustment for Interest and Inflation			$60,323
Total Plant Investment (TPI)			$540,873
Prepaid Royalties			$1,884
Initial Catalyst and Chemical Inventory			$61
Startup Costs			$13,039
Spare Parts			$2,403
Working Capital			$5,788
Land,	200	Acres	$1,300
Total Capital Requirement (TCR)			$565,348
		$/kW	1370

ANNUAL OPERATING COSTS

Capacity Factor = 85 %

COST ITEM		QUANTITY		UNIT $ PRICE		ANNUAL COST, K$
	Coal (Illinois #6)	3,171	T/D	$24.36	/T	$23,964
Consumable Materials						
	Water	1,263	T/D	$0.19	/T	$74
	MDEA Solvent	403.2	Lb/D	$1.45	/Lb	$181
	Claus Catalyst	0.01	T/D	$470	/T	$1
	SCOT Activated Alum	15.9	Lb/D	$0.67	/Lb	$3
	SCOT Cobalt Catalyst					$5
	SCOT Chemicals					$16
Ash/Sorbent Disposal Costs		321	T/D	$8.00	/T	$797
Plant Labor						
Oper Labor (incl benef)		15	Men/shift	$34.00	/Hr.	$4,455
Supervision & Clerical						$2,605
Maintenance Costs	2.2%					$10,572
Royalties						$240
Other Operating Costs						$868
	Total Operating Costs					$43,783
By-Product Credits						
	Sulfur	78.0	T/D	$75.00	/T	$1,814
	___________________	0.0	T/D	$0.00	/T	$0
	___________________	0.0	T/D	$0.00	/T	$0
	___________________	0.0	T/D	$0.00	/T	$0
	Total By-Product Credits					$1,814
	Net Operating Costs					$41,969

BASES AND ASSUMPTIONS

A. CAPITAL BASES AND DETAILS

	QUANTITY		UNIT $ PRICE		COST, K$
Initial Cat./Chem. Inventory					
Water	32212	T	$0.19	/T	$6
MDEA Solvent	10282	Lb	$1.45	/Lb	$15
Claus Catalyst	0.3	T	$470	/T	$0
SCOT Activated Alum	405	Lb	$0.67	/Lb	$0
SCOT Cobalt Catalyst					$16
SCOT Chemicals					$24
Total Catalyst and Chemical Inventory					$61
Startup costs					
Plant modifications,	2	% TPI			$10,817
Operating costs					$1,643
Fuel					$579
Total Startup Costs					$13,039
Working capital					
Fuel & Consumables inv	60	days supply			$4,685
By-Product inventory	30	days supply			$175
Direct expenses	30	days			$928
Total Working Capital					$5,788

B. ECONOMIC ASSUMPTIONS

Project life	20	Years
Book life	20	Years
Tax life	20	Years
Federal and state income tax rate	38.0	%
Tax depreciation method	ACRS	
Investment Tax Credit	0.0	%

Financial structure

Type of Security	% of Total	Current Dollar Cost, %	Current Dollar Ret, %	Constant Dollar Cost, %	Constant Dollar Ret, %
Debt	80	9.0	7.2	5.8	4.6
Preferred Stock	0	3.0	0.0	0.0	0.0
Common Stock	20	20.0	4.0	16.5	3.3
Discount rate (cost of capital)			11.2		7.9

Inflation rate, % per year	3.0
Real Escalation rates (over inflation)	
Fuel, % per year	-1.1
Operating & Maintenance, % per year	0.0

C. COST OF ELECTRICITY

The approach to determining the cost of electricity is based upon the methodology described in the Technical Assessment Guide, published by the Electric Power Research Institute. The cost of electricity is stated in terms of 10th year levelized dollars.

Levelizing Factors	Current $	Constant $
Capital Carrying Charge, 10th yr	0.179	0.148
Fuel, 10th year	1.091	0.948
Operating & Maintenance, 10th yr	1.151	1.000

Cost of Electricity - Levelized	mills/kWh	mills/kWh
Capital Charges	32.9	27.3
Fuel Costs	8.5	7.4
Consumables	0.4	0.4
Fixed Operating & Maintenance	6.0	5.2
Variable Operating & Maintenance	1.1	0.9
By-product	-0.7	-0.6
Total Cost of Electricity	48.2	40.6

Combined Cycle

IGCC Shell / CGCU / “G” Gas Turbine / CO_2 Capture

Shell CGCU I (co2 , h2, power) 351 MW POWER PLANT

1st Q 2002 Dollar

Total Plant Investment AREA NO	PLANT SECTION DESCRIPTION	PROCESS CONT, %	PROCESS CONT, K$	COST, K$ W/O CONT
11	Coal Preparation	0	$0	$18,436
12	Oxygen Plant (includes air cpr + O2 cpr)	0	$0	$51,308
12	Shell Gasifier	5	$4,041	$80,826
12	Quench Gas Compressor	5	$98	$1,951
14	Gas Cooling	0	$0	$9,606
14	Shift Reaction System	0	$0	$16,263
14	SELEXOL (H2S & CO2)	0	$0	$29,529
14	CO2 Compression/Recovery	0	$0	$19,374
14	Claus	0	$0	$10,234
14	SCOT	0	$0	$4,328
14	PSA	0	$0	$9,572
15	Gas Turbine System (62 MWe)	5	$627	$12,547
15	HRSG/Steam Turbine	5	$1,215	$24,291
17	Advanced Power System (H2 - fuel cell)	25	$27,518	$110,071
18	Water Systems	0	$0	$21,909
30	Civil/Structural/Architectural	0	$0	$24,697
40	Piping	0	$0	$21,909
50	Control/ Instrumentation	0	$0	$15,933
60	Electrical	0	$0	$34,655

Subtotal, Process Plant Cost		$517,439
Engineering Fees		$51,744
Process Contingency (Using cont. listed)		$33,498
Project Contingency,	15 % Proc Plt & Gen Plt Fac	$77,616
Total Plant Cost (TPC)		$680,297
Plant Construction Period,	4.0 Years (1 or more)	
Construction Interest Rate,	11.2 %	
Adjustment for Interest and Inflation		$85,397
Total Plant Investment (TPI)		$765,695
Prepaid Royalties		$2,587
Initial Catalyst and Chemical Inventory		$76
Startup Costs		$17,972
Spare Parts		$3,401
Working Capital		$6,011
Land,	200 Acres	$1,300
Total Capital Requirement (TCR)		$797,043
	$/kW	2270

ANNUAL OPERATING COSTS

Capacity Factor = 85 %

COST ITEM	QUANTITY		UNIT $ PRICE		ANNUAL COST, K$
Coal (Illinois #6)	3,171	T/D	$24.36	/T	$23,964
Consumable Materials					
Water	1,263	T/D	$0.19	/T	$74
Selexol Solvent	806.4	Lb/D	$1.45	/Lb	$363
Claus Catalyst	0.01	T/D	$470	/T	$1
SCOT Activated Alun	15.9	Lb/D	$0.67	/Lb	$3
SCOT Cobalt Catalyst					$5
SCOT Chemicals					$16
Ash/Sorbent Disposal Costs	321	T/D	$8.00	/T	$797
Plant Labor					
Oper Labor (incl benef)	15	Men/shift	$34.00	/Hr.	$4,455
Supervision & Clerical					$3,133
Maintenance Costs 2.2%					$14,967
Royalties					$240
Other Operating Costs					$1,044
Total Operating Costs					$49,062
By-Product Credits					
Sulfur	78.0	T/D	$75.00	/T	$1,814
___________________	0.0	T/D	$0.00	/T	$0
___________________	0.0	T/D	$0.00	/T	$0
___________________	0.0	T/D	$0.00	/T	$0
Total By-Product Credits					$1,814
Net Operating Costs					$47,248

BASES AND ASSUMPTIONS

A. CAPITAL BASES AND DETAILS

	QUANTITY		UNIT $ PRICE		COST, K$
Initial Cat./Chem. Inventory					
Water	32212	T	$0.19	/T	$6
Selexol Solvent	20563	Lb	$1.45	/Lb	$30
Claus Catalyst	0.3	T	$470	/T	$0
SCOT Activated Alun	405	Lb	$0.67	/Lb	$0
SCOT Cobalt Catalyst					$16
SCOT Chemicals					$24
Total Catalyst and Chemical Inventory					$76
Startup costs					
Plant modifications,	2	% TPI			$15,314
Operating costs					$2,079
Fuel					$579
Total Startup Costs					$17,972
Working capital					
Fuel & Consumables inv	60	days supply			$4,720
By-Product inventory	30	days supply			$175
Direct expenses	30	days			$1,116
Total Working Capital					$6,011

B. ECONOMIC ASSUMPTIONS

Project life	20	Years
Book life	20	Years
Tax life	20	Years
Federal and state income tax rate	38.0	%
Tax depreciation method	ACRS	
Investment Tax Credit	0.0	%

Financial structure

Type of Security	% of Total	Current Dollar Cost, %	Current Dollar Ret, %	Constant Dollar Cost, %	Constant Dollar Ret, %
Debt	80	9.0	7.2	5.8	4.6
Preferred Stock	0	3.0	0.0	0.0	0.0
Common Stock	20	20.0	4.0	16.5	3.3
Discount rate (cost of capital)			11.2		7.9

Inflation rate, % per year	3.0
Real Escalation rates (over inflation)	
Fuel, % per year	-1.1
Operating & Maintenance, % per year	0.0

C. COST OF ELECTRICITY

The approach to determining the cost of electricity is based upon the methodology described in the Technical Assessment Guide, published by the Electric Power Research Institute. The cost of electricity is stated in terms of 10th year levelized dollars.

	Current $	Constant $
Levelizing Factors		
Capital Carrying Charge, 10th yr	0.179	0.148
Fuel, 10th year	1.091	0.948
Operating & Maintenance, 10th yr	1.151	1.000

Cost of Electricity - Levelized	mills/kWh	mills/kWh
Capital Charges	54.6	45.3
Fuel Costs	10.0	8.7
Consumables	0.6	0.5
Fixed Operating & Maintenance	8.9	7.8
Variable Operating & Maintenance	1.6	1.4
By-product	-0.8	-0.7
Total Cost of Electricity	74.8	62.9

Hydraulic Air Compression (HAC)

Natural Gas HAC - No CO_2 Capture

Hydraulic Air Compression Technology Combined Cycle **324 MW POWER PLANT**

(Natural Gas, No CO2 Capture) 1st Q 2002 Dollar

Total Plant Investment		PROCESS	PROCESS	COST, K$
AREA NO	PLANT SECTION DESCRIPTION	CONT, %	CONT, K$	W/O CONT
	GT Expander / Combustor	25	$7,980	$31,920
	HV Cpr System	25	$11,736	$46,945
	Well	10	$23	$225
	Recuperator + Air Heaters	0	$0	$6,863
	HRSG/Turbine Package	0	$0	$2,610
18	Water Systems	0	$0	$6,288
30	Civil/Structural/Architectural	0	$0	$12,310
40	Piping	0	$0	$6,288
50	Control/ Instrumentation	0	$0	$7,085
60	Electrical	0	$0	$13,993
	Subtotal, Process Plant Cost		$19,739	$134,527

Engineering Fees		$13,453
Process Contingency (Using cont. listed)		$19,739
Project Contingency,	15 % Proc Plt & Gen Plt Fac	$20,179
Total Plant Cost (TPC)		$187,897
Plant Construction Period,	2.0 Years (1 or more)	
Construction Interest Rate,	11.2 %	
Adjustment for Interest and Inflation		$7,460
Total Plant Investment (TPI)		$195,357
Prepaid Royalties		$673
Initial Catalyst and Chemical Inventory		$68
Startup Costs		$10,822
Spare Parts		$939
Working Capital		$12,417
Land, 100 Acres	@ $1500/acre	$150
Total Capital Requirement (TCR)		$220,425
	$/kW	681

ANNUAL OPERATING COSTS

Capacity Factor = 85 %

			UNIT $		ANNUAL
Consumables			UNIT $		ANNUAL
COST ITEM	QUANTITY		PRICE		COST, K$
Natural Gas	54,568	1000 SCF/D	$3.20	$/1000 SCF	$54,175
Water	562,826	T/d	$0.05	/T	$8,294
Plant Labor					
Oper Labor (incl benef)	5	Men/shift	$34.00	/Hr.	$1,485
Supervision & Clerical					$942
Maintenance Costs	2.2%				$4,134
Insurance & Local Taxes					$3,758
Other Operating Costs					$314
Total Operating Costs					$73,102

BASES AND ASSUMPTIONS

A. CAPITAL BASES AND DETAILS

	QUANTITY		UNIT $ PRICE		COST, K$
Initial Cat./Chem. Inventory					
Water	1,435,206	tons	$0.05	/T	$68
Total Catalyst and Chemical Inventory					$68
Startup costs					
Plant modifications,	2	% TPI			$3,907
Operating costs					$6,914
Total Startup Costs					$10,822
Working capital					
Fuel & Consumables inv	60	days supply			$12,081
Direct expenses	30	days			$335
Total Working Capital					$12,417

B. ECONOMIC ASSUMPTIONS

Project life	20	Years
Book life	20	Years
Tax life	20	Years
Federal and state income tax rate	38.0	%
Tax depreciation method	MACRS	
Investment Tax Credit	0.0	%

Financial structure

Type of Security	% of Total	Current Dollar Cost, %	Current Dollar Ret, %	Constant Dollar Cost, %	Constant Dollar Ret, %
Debt	80	9.0	7.2	5.8	4.6
Preferred Stock	0	0.2	0.0	0.0	0.0
Common Stock	20	20.0	4.0	16.5	3.3
Discount rate (cost of capital)			11.2		7.9

Inflation rate, % per year	3.0
Real Escalation rates (over inflation)	
Fuel, % per year	0.2
Operating & Maintenance, % per year	0.0

C. COST OF ELECTRICITY

The approach to determining the cost of electricity is based upon the methodology described in the Technical Assessment Guide, published by the Electric Power Research Institute. The cost of electricity is stated in terms of 10th year levelized dollars.

Levelizing Factors	Current $	Constant $
Capital Carrying Charge, 10th yr	0.179	0.148
Fuel, 10th year	1.162	1.010
Operating & Maintenance, 10th yr	1.151	1.000

Cost of Electricity - Levelized	mills/kWh	mills/kWh
Capital Charges	16.4	13.6
Fuel Costs	26.1	22.7
Consumables	4.0	3.4
Fixed Operating & Maintenance	4.3	3.8
Variable Operating & Maintenance	0.8	0.7
By-product	0.0	0.0
Total Cost of Electricity	51.6	44.2

Hydraulic Air Compression (HAC)

Natural Gas HAC - CO_2 Capture

Hydraulic Air Compression Technology Combined Cycle **300 MW POWER PLANT**

(Natural Gas, CO2 Capture) 1st Q 2002 Dollar

Total Plant Investment AREA NO	PLANT SECTION DESCRIPTION	PROCESS CONT, %	PROCESS CONT, K$	COST, K$ W/O CONT
	GT Expander / Combustor	25	$7,980	$31,920
	HV Cpr System	25	$11,736	$46,945
	Well	10	$23	$225
	Recuperator + Air Heaters	0	$0	$8,215
	HRSG	0	$0	$5,837
	Amine System	5	$3,541	$70,815
	CO2 Compression/drying	5	$574	$11,488
18	Water Systems	0	$0	$6,613
30	Civil/Structural/Architectural	0	$0	$12,947
40	Piping	0	$0	$6,613
50	Control/ Instrumentation	0	$0	$7,451
60	Electrical	0	$0	$14,716
	Subtotal, Process Plant Cost		$23,854	$223,786

Engineering Fees		$22,379
Process Contingency (Using cont. listed)		$19,739
Project Contingency,	15 % Proc Plt & Gen Plt Fac	$33,568
Total Plant Cost (TPC)		$299,471
Plant Construction Period,	2.0 Years (1 or more)	
Construction Interest Rate,	11.2 %	
Adjustment for Interest and Inflation		$11,889
Total Plant Investment (TPI)		$311,360
Prepaid Royalties		$1,119
Initial Catalyst and Chemical Inventory		$68
Startup Costs		$14,219
Spare Parts		$1,497
Working Capital		$13,841
Land, 100 Acres	@ $1500/acre	$150
Total Capital Requirement (TCR)		$342,254
	$/kW	1140

ANNUAL OPERATING COSTS

Capacity Factor = 85 %

			UNIT $		ANNUAL
Consumables			UNIT $		ANNUAL
COST ITEM	QUANTITY		PRICE		COST, K$
Natural Gas	61,439	1000 SCF/D	$3.20	$/1000 SCF	$60,997
Water	562,826	T/d	$0.05	/T	$8,294
Amine Chemicals	141	ton CO2/hr	$3.00	/ton CO2 Captu	$3,147
Plant Labor					
Oper Labor (incl benef)	5	Men/shift	$34.00	/Hr.	$1,485
Supervision & Clerical					$1,236
Maintenance Costs 2.2%					$6,588
Insurance & Local Taxes					$5,989
Other Operating Costs					$412
Total Operating Costs					$85,002

BASES AND ASSUMPTIONS

A. CAPITAL BASES AND DETAILS

	QUANTITY		UNIT $ PRICE		COST, K$
Initial Cat./Chem. Inventory					
Water	1,435,206	tons	$0.05	/T	$68
Amine Chemicals	20,120	(7 days CO2)	$3.00	/ton CO2	$60
Total Catalyst and Chemical Inventory					$68
Startup costs					
Plant modifications,	2	% TPI			$6,227
Operating costs					$7,992
Total Startup Costs					$14,219
Working capital					
Fuel & Consumables inv	60	days supply			$13,400
Direct expenses	30	days			$440
Total Working Capital					$13,841

B. ECONOMIC ASSUMPTIONS

Project life	20	Years
Book life	20	Years
Tax life	20	Years
Federal and state income tax rate	38.0	%
Tax depreciation method	MACRS	
Investment Tax Credit	0.0	%

Financial structure

Type of Security	% of Total	Current Dollar Cost, %	Current Dollar Ret, %	Constant Dollar Cost, %	Constant Dollar Ret, %
Debt	80	9.0	7.2	5.8	4.6
Preferred Stock	0	0.2	0.0	0.0	0.0
Common Stock	20	20.0	4.0	16.5	3.3
Discount rate (cost of capital)			11.2		7.9

Inflation rate, % per year	3.0
Real Escalation rates (over inflation)	
Fuel, % per year	0.2
Operating & Maintenance, % per year	0.0

C. COST OF ELECTRICITY

The approach to determining the cost of electricity is based upon the methodology described in the Technical Assessment Guide, published by the Electric Power Research Institute. The cost of electricity is stated in terms of 10th year levelized dollars.

	Current $	Constant $
Levelizing Factors		
Capital Carrying Charge, 10th yr	0.179	0.148
Fuel, 10th year	1.162	1.010
Operating & Maintenance, 10th yr	1.151	1.000

Cost of Electricity - Levelized	mills/kWh	mills/kWh
Capital Charges	27.4	22.7
Fuel Costs	31.7	27.6
Consumables	4.3	3.7
Fixed Operating & Maintenance	6.9	6.0
Variable Operating & Maintenance	1.2	1.1
By-product	0.0	0.0
Total Cost of Electricity	71.5	61.0

Hydraulic Air Compression (HAC)

Coal Syngas HAC

Destec (E-Gas™) / CGCU / "G" GT / No CO_2 Capture

Destec Gasification / CGCU / HAC

Hydraulic Air Compression Technology Combined Cycle **326 MW POWER PLANT**

(COAL, No CO2 Capture) 1st Q 2002 Dollar

Total Plant Investment AREA NO	PLANT SECTION DESCRIPTION	PROCESS CONT, %	PROCESS CONT, K$	COST, K$ W/O CONT
11	Coal Slurry Preparation	0	$0	$24,429
12	Oxygen Plant	0	$0	$38,848
12	Destec Gasifier	5	$1,008	$20,163
12	Recycle Gas Compressor / Fuel Coolers	5	$124	$2,484
14	Low Temperature Gas Cooling	0	$0	$13,824
14	MDEA	0	$0	$4,894
14	Claus	0	$0	$9,218
14	SCOT	0	$0	$3,898
15	Hydraulic Air Compression System	25	$12,371	$49,485
15	GT Expander / Combustor	25	$7,980	$31,920
15	Well	10	$23	$225
15	Recuperator	0	$0	$16,000
15	HRSG/Steam Turbine	5	$761	$15,221
18	Water Systems	0	$0	$12,684
30	Civil/Structural/Architectural	0	$0	$14,298
40	Piping	0	$0	$12,684
50	Control/ Instrumentation	0	$0	$9,224
60	Electrical	0	$0	$20,063

Subtotal, Process Plant Cost		$299,565
Engineering Fees		$29,956
Process Contingency (Using cont. listed)		$22,267
Project Contingency,	15 % Proc Plt & Gen Plt Fac	$44,935
Total Plant Cost (TPC)		$396,723
Plant Construction Period,	4.0 Years (1 or more)	
Construction Interest Rate,	11.2 %	
Adjustment for Interest and Inflation		$49,800
Total Plant Investment (TPI)		$446,523
Prepaid Royalties		$1,498
Initial Catalyst and Chemical Inventory		$806
Startup Costs		$10,908
Spare Parts		$1,984
Working Capital		$5,022
Land,	200 Acres	$1,300
Total Capital Requirement (TCR)		$468,041
	$/kW	1436

ANNUAL OPERATING COSTS

Capacity Factor = 85 %

COST ITEM		QUANTITY		UNIT $ PRICE		ANNUAL COST, K$
Coal (Illinois #6)		2,706	T/D	$24.36	/T	$20,449
Consumable Materials						
Water		3,073	T/D	$0.19	/T	$181
HAC Makeup Water		607,513	T/D	$0.05	/T	$8,953
MDEA Solvent		403.2	Lb/D	$1.45	/Lb	$181
Claus Catalyst		0.01	T/D	$470	/T	$1
SCOT Activated Alun		15.9	Lb/D	$0.67	/Lb	$3
SCOT Cobalt Catalyst						$5
SCOT Chemicals						$16
Ash/Sorbent Disposal Costs		358	T/D	$8.00	/T	$889
Plant Labor						
Oper Labor (incl benef)		15	Men/shift	$34.00	/Hr.	$4,455
Supervision & Clerical						$2,384
Maintenance Costs	2.2%					$8,728
Royalties						$204
Other Operating Costs						$795
Total Operating Costs						$47,246
By-Product Credits						
Sulfur		65.4	T/D	$75.00	/T	$1,521
____________________		0.0	T/D	$0.00	/T	$0
____________________		0.0	T/D	$0.00	/T	$0
____________________		0.0	T/D	$0.00	/T	$0
Total By-Product Credits						$1,521
Net Operating Costs						$45,725

BASES AND ASSUMPTIONS

A. CAPITAL BASES AND DETAILS

	QUANTITY		UNIT $ PRICE		COST, K$
Initial Cat./Chem. Inventory					
Water	78368	T	$0.19	/T	$15
HAC Makeup Water	15491570	T	$0.05	/T	$736
MDEA Solvent	10282	Lb	$1.45	/Lb	$15
Claus Catalyst	0.3	T	$470	/T	$0
SCOT Activated Alum	405	Lb	$0.67	/Lb	$0
SCOT Cobalt Catalyst					$16
SCOT Chemicals					$24
Total Catalyst and Chemical Inventory					$806
Startup costs					
Plant modifications,	2	% TPI			$8,930
Operating costs					$1,483
Fuel					$494
Total Startup Costs					$10,908
Working capital					
Fuel & Consumables inv	60	days supply			$4,026
By-Product inventory	30	days supply			$147
Direct expenses	30	days			$849
Total Working Capital					$5,022

B. ECONOMIC ASSUMPTIONS

Project life	20	Years
Book life	20	Years
Tax life	20	Years
Federal and state income tax rate	38.0	%
Tax depreciation method	MACRS	
Investment Tax Credit	0.0	%

Financial structure

Type of Security	% of Total	Current Dollar Cost, %	Current Dollar Ret, %	Constant Dollar Cost, %	Constant Dollar Ret, %
Debt	80	9.0	7.2	5.8	4.6
Preferred Stock	0	3.0	0.0	0.0	0.0
Common Stock	20	20.0	4.0	16.5	3.3
Discount rate (cost of capital)			11.2		7.9

Inflation rate, % per year	3.0
Real Escalation rates (over inflation)	
Fuel, % per year	-1.1
Operating & Maintenance, % per year	0.0

C. COST OF ELECTRICITY

The approach to determining the cost of electricity is based upon the methodology described in the Technical Assessment Guide, published by the Electric Power Research Institute. The cost of electricity is stated in terms of 10th year levelized dollars.

Levelizing Factors	Current $	Constant $
Capital Carrying Charge, 10th yr	0.179	0.148
Fuel, 10th year	1.091	0.948
Operating & Maintenance, 10th yr	1.151	1.000

Cost of Electricity - Levelized	mills/kWh	mills/kWh
Capital Charges	34.5	28.6
Fuel Costs	9.2	8.0
Consumables	4.9	4.2
Fixed Operating & Maintenance	6.7	5.8
Variable Operating & Maintenance	1.2	1.0
By-product	-0.7	-0.6
Total Cost of Electricity	55.7	47.0

Hydraulic Air Compression (HAC)

Coal Syngas HAC
Destec High Pressure (E-Gas™) / HGCU /
"G" GT / CO_2 Capture

Hydraulic Air Compression Technology Combined Cycle

Destec Gasification / HGCU / HSD **312 MW POWER PLANT**

(COAL, CO2 Capture) 1st Q 2002 Dollar

Total Plant Investment AREA NO	 PLANT SECTION DESCRIPTION	PROCESS CONT, %	PROCESS CONT, K$	COST, K$ W/O CONT
11	Coal Slurry Preparation	0	$0	$27,689
12	Oxygen Plant	0	$0	$41,336
12	Destec Gasifier/Syngas Cooler	5	$4,170	$83,394
12	Recycle Compressors	5	$40	$790
14	Gas Conditioning	10	$714	$7,139
14	Transport Desulfurizer	15	$847	$5,646
14	Sulfuric Acid Plant	0	$0	$19,930
14	Hydrogen Separation Device	50	$5,041	$10,081
15	CO2 Compressor	0	$0	$28,491
15	H2 Compressor	0	$0	$4,609
15	Gas Expander	0	$0	$6,844
15	Hydraulic Air Compression System	25	$5,315	$53,161
15	GT Expander / Combustor	25	$7,980	$31,920
15	Well	10	$195	$225
15	Recuperator	0	$0	$15,500
15	HRSG/Steam Turbine	5	$818	$16,361
18	Water Systems	0	$0	$12,359
30	Civil/Structural/Architectural	0	$0	$21,893
40	Piping	0	$0	$12,359
50	Control/ Instrumentation	0	$0	$14,125
60	Electrical	0	$0	$30,721

Subtotal, Process Plant Cost		$444,571
Engineering Fees		$44,457
Process Contingency (Using cont. listed)		$25,119
Project Contingency,	15 % Proc Plt & Gen Plt Fac	$66,686
Total Plant Cost (TPC)		$580,833
Plant Construction Period,	4.0 Years (1 or more)	
Construction Interest Rate,	11.2 %	
Adjustment for Interest and Inflation		$72,912
Total Plant Investment (TPI)		$653,745
Prepaid Royalties		$2,223
Initial Catalyst and Chemical Inventory		$1,710
Startup Costs		$15,587
Spare Parts		$2,904
Working Capital		$6,366
Land,	200 Acres	$1,300
Total Capital Requirement (TCR)		$683,834
	$/kW	2189

ANNUAL OPERATING COSTS

Capacity Factor = 85 %

COST ITEM	QUANTITY		UNIT $ PRICE		ANNUAL COST, K$
Coal (Illinois #6)	3,236	T/D	$24.36	/T	$24,456
Consumable Materials					
Process Water	4,820	T/D	$0.19	/T	$284
HAC Makeup Water	673,200	T/D	$0.05	/T	$9,921
HGCU Sorbent	0.03	T/D	$6,000	/T	$65
Nahcolite	2.3	T/D	$275	/T	$196
Ash/Sorbent Disposal Costs	487	T/D	$8.00	/T	$1,209
Plant Labor					
Oper Labor (incl benef)	15	Men/shift	$34.00	/Hr.	$4,455
Supervision & Clerical					$2,870
Maintenance Costs 2.2%					$12,778
Royalties					$245
Other Operating Costs					$957
Total Operating Costs					$57,435
By-Product Credits					
Sulfuric Acid	249.4	T/D	$68.00	/T	$5,262
____________________	0.0	T/D	$0.00	/T	$0
____________________	0.0	T/D	$0.00	/T	$0
____________________	0.0	T/D	$0.00	/T	$0
Total By-Product Credits					$5,262
Net Operating Costs					$52,173

BASES AND ASSUMPTIONS

A. CAPITAL BASES AND DETAILS

	QUANTITY		UNIT $ PRICE		COST, K$
Initial Cat./Chem. Inventory					
Water	122909	T	$0.19	/T	$23
HAC Makeup Water	17166600	T	$0.05	/T	$815
HGCU Sorbent	15	T	$6,000	/T	$16
Nahcolite	59	T	$275	/T	$855
Total Catalyst and Chemical Inventory					$1,710
Startup costs					
Plant modifications,	2	% TPI			$13,075
Operating costs					$1,921
Fuel					$591
Total Startup Costs					$15,587
Working capital					
Fuel & Consumables inv	60	days supply			$4,835
By-Product inventory	30	days supply			$509
Direct expenses	30	days			$1,022
Total Working Capital					$6,366

B. ECONOMIC ASSUMPTIONS

Project life	20	Years
Book life	20	Years
Tax life	20	Years
Federal and state income tax rate	38.0	%
Tax depreciation method	MACRS	
Investment Tax Credit	0.0	%

Financial structure

Type of Security	% of Total	Current Dollar Cost, %	Current Dollar Ret, %	Constant Dollar Cost, %	Constant Dollar Ret, %
Debt	80	9.0	7.2	5.8	4.6
Preferred Stock	0	3.0	0.0	0.0	0.0
Common Stock	20	20.0	4.0	16.5	3.3
Discount rate (cost of capital)			11.2		7.9

Inflation rate, % per year	3.0
Real Escalation rates (over inflation)	
Fuel, % per year	-1.1
Operating & Maintenance, % per year	0.0

C. COST OF ELECTRICITY

The approach to determining the cost of electricity is based upon the methodology described in the Technical Assessment Guide, published by the Electric Power Research Institute. The cost of electricity is stated in terms of 10th year levelized dollars.

	Current $	Constant $
Levelizing Factors		
Capital Carrying Charge, 10th yr	0.179	0.148
Fuel, 10th year	1.091	0.948
Operating & Maintenance, 10th yr	1.151	1.000

Cost of Electricity - Levelized	mills/kWh	mills/kWh
Capital Charges	52.6	43.6
Fuel Costs	11.5	10.0
Consumables	5.8	5.0
Fixed Operating & Maintenance	9.0	7.8
Variable Operating & Maintenance	1.6	1.4
By-product	-2.6	-2.3
Total Cost of Electricity	77.8	65.5

Rocket Engine (CES) - CO_2 Capture

Natural Gas CES (gas generator)

Natural Gas CES **398 MW POWER PLANT**

1st Q 2002 Dollar

Total Plant Investment

AREA NO	PLANT SECTION DESCRIPTION	PROCESS CONT, %	PROCESS CONT, K$	COST, K$ W/O CONT
12	Oxygen Plant	0	$0	$117,982
14	CH4 Compressor	0	$0	$796
14	Gas Generator + Reheator	25	$1,615	$6,460
15	CO2 Compressor	10	$3,151	$31,513
15	CES Turbines	25	$5,216	$20,864
18	Water Systems	0	$0	$12,611
30	Civil/Structural/Architectural	0	$0	$24,688
40	Piping	0	$0	$12,611
50	Control/ Instrumentation	0	$0	$14,209
60	Electrical	0	$0	$28,063

Subtotal, Process Plant Cost		$269,796
Engineering Fees		$26,980
Process Contingency (Using cont. listed)		$9,982
Project Contingency,	15 % Proc Plt & Gen Plt Fac	$40,469
Total Plant Cost (TPC)		$347,228
Plant Construction Period,	3.0 Years (1 or more)	
Construction Interest Rate,	11.2 %	
Adjustment for Interest and Inflation		$28,300
Total Plant Investment (TPI)		$375,527
Prepaid Royalties		$1,349
Initial Catalyst and Chemical Inventory		$16
Startup Costs		$8,662
Spare Parts		$1,736
Working Capital		$697
Land, 200 Acres	@ $1500/acre	$300
Total Capital Requirement (TCR)		$388,288
	$/kW	975

ANNUAL OPERATING COSTS

Capacity Factor = 85 %

COST ITEM		QUANTITY		UNIT $ PRICE		ANNUAL COST, K$
Natural Gas		74,066	1000 SCF/day	$3.20	/1000 SCF	$73,533
Consumable Materials						
Water		3,388	T/D	$0.19	/T	$200
Ash/Sorbent Disposal Costs		0	T/D	$8.00	/T	$0
Plant Labor						
Oper Labor (incl benef)		10	Men/shift	$34.00	/Hr.	$2,970
Supervision & Clerical						$1,808
Maintenance Costs	2.2%					$7,639
Royalties						$735
Other Operating Costs						$603
Total Operating Costs						$87,488
By-Product Credits						
		0.0	T/D	$0.00	/T	$0
____________________		0.0	T/D	$0.00	/T	$0
____________________		0.0	T/D	$0.00	/T	$0
____________________		0.0	T/D	$0.00	/T	$0
Total By-Product Credits						$0
Net Operating Costs						$87,488

BASES AND ASSUMPTIONS

A. CAPITAL BASES AND DETAILS

	QUANTITY		UNIT $ PRICE		COST, K$
Initial Cat./Chem. Inventory					
Water	86387	T	$0.19	/T	$16
Total Catalyst and Chemical Inventory					$16
Startup costs					
Plant modifications,	2	% TPI			$7,511
Operating costs					1,149.85
Fuel					$2
Total Startup Costs					$8,662
Working capital					
Fuel & Consumables inv	60	days supply			$53
By-Product inventory	30	days supply			$0
Direct expenses	30	days			$644
Total Working Capital					$697

B. ECONOMIC ASSUMPTIONS

Project life	20	Years
Book life	20	Years
Tax life	20	Years
Federal and state income tax rate	38.0	%
Tax depreciation method	MACRS	
Investment Tax Credit	0.0	%

Financial structure

Type of Security	% of Total	Current Dollar Cost, %	Current Dollar Ret, %	Constant Dollar Cost, %	Constant Dollar Ret, %
Debt	80	9.0	7.2	5.8	4.6
Preferred Stock	0	3.0	0.0	0.0	0.0
Common Stock	20	20.0	4.0	16.5	3.3
Discount rate (cost of capital)			11.2		7.9

Inflation rate, % per year	3.0
Real Escalation rates (over inflation)	
Fuel, % per year	0.2
Operating & Maintenance, % per year	0.0

C. COST OF ELECTRICITY

The approach to determining the cost of electricity is based upon the methodology described in the Technical Assessment Guide, published by the Electric Power Research Institute. The cost of electricity is stated in terms of 10th year levelized dollars.

	Current $	Constant $
Levelizing Factors		
Capital Carrying Charge, 10th yr	0.179	0.148
Fuel, 10th year	1.162	1.010
Operating & Maintenance, 10th yr	1.151	1.000

Cost of Electricity - Levelized	mills/kWh	mills/kWh
Capital Charges	23.4	19.4
Fuel Costs	28.8	25.0
Consumables	0.1	0.1
Fixed Operating & Maintenance	4.5	3.9
Variable Operating & Maintenance	0.8	0.7
By-product	0.0	0.0
Total Cost of Electricity	57.7	49.2

Rocket Engine (CES) - CO_2 Capture

Coal Syngas CES (gas generator) – Destec HP / HGCU

Destec Coal CES **406 MW POWER PLANT**

1st Q 2002 Dollar

Total Plant Investment AREA NO	PLANT SECTION DESCRIPTION	PROCESS CONT, %	PROCESS CONT, K$	COST, K$ W/O CONT
11	Coal Slurry Preparation	0	$0	$29,661
12	Oxygen Plant	0	$0	$132,368
12	Destec Gasifier	5	$4,259	$85,172
14	Gas Conditioning	10	$912	$9,118
14	Transport Desulfurizer	15	$882	$5,879
14	Sulfuric Acid Plant	0	$0	$21,301
14	Gas Generator + Reheator	25	$1,646	$6,584
15	CO2 Compressor	10	$6,016	$60,164
15	CES Turbines	25	$6,510	$26,039
18	Water Systems	0	$0	$13,170
30	Civil/Structural/Architectural	0	$0	$23,330
40	Piping	0	$0	$13,170
50	Control/ Instrumentation	0	$0	$15,051
60	Electrical	0	$0	$32,737

Subtotal, Process Plant Cost		$473,742
Engineering Fees		$47,374
Process Contingency (Using cont. listed)		$20,224
Project Contingency,	15 % Proc Plt & Gen Plt Fac	$71,061
Total Plant Cost (TPC)		$612,402
Plant Construction Period,	4.0 Years (1 or more)	
Construction Interest Rate,	11.2 %	
Adjustment for Interest and Inflation		$76,875
Total Plant Investment (TPI)		$689,276
Prepaid Royalties		$2,369
Initial Catalyst and Chemical Inventory		$122
Startup Costs		$16,319
Spare Parts		$3,062
Working Capital		$6,898
Land, 200 Acres	@ $1500/acre	$300
Total Capital Requirement (TCR)		$718,346
	$/kW	1768

ANNUAL OPERATING COSTS

Capacity Factor = 85 %

COST ITEM		QUANTITY		UNIT $ PRICE		ANNUAL COST, K$
Coal (Illinois #6)		3,570	T/D	$24.36	/T	$26,982
Consumable Materials						
Water		1,187	T/D	$0.19	/T	$70
HGCU Sorbent		0.04	T/D	$6,000	/T	$72
Nahcolite		2.3	T/D	$275	/T	$196
Ash/Sorbent Disposal Costs		121	T/D	$8.00	/T	$299
Plant Labor						
Oper Labor (incl benef)		15	Men/shift	$34.00	/Hr.	$4,455
Supervision & Clerical						$2,953
Maintenance Costs	2.2%					$13,473
Royalties						$270
Other Operating Costs						$984
Total Operating Costs						$49,754
By-Product Credits						
Sulfuric Acid		275.9	T/D	$68.00	/T	$5,820
___________________		0.0	T/D	$0.00	/T	$0
___________________		0.0	T/D	$0.00	/T	$0
___________________		0.0	T/D	$0.00	/T	$0
Total By-Product Credits						$5,820
Net Operating Costs						$43,934

BASES AND ASSUMPTIONS

A. CAPITAL BASES AND DETAILS

	QUANTITY		UNIT $ PRICE		COST, K$
Initial Cat./Chem. Inventory					
Water	30277	T	$0.19	/T	$6
HGCU Sorbent	17	T	$6,000	/T	$100
Nahcolite	59	T	$275	/T	$16
Total Catalyst and Chemical Inventory					$122
Startup costs					
Plant modifications,	2	% TPI			$13,786
Operating costs					$1,881
Fuel					$652
Total Startup Costs					$16,319
Working capital					
Fuel & Consumables inv	60	days supply			$5,283
By-Product inventory	30	days supply			$563
Direct expenses	30	days			$1,052
Total Working Capital					$6,898

B. ECONOMIC ASSUMPTIONS

Project life	20	Years
Book life	20	Years
Tax life	20	Years
Federal and state income tax rate	38.0	%
Tax depreciation method	MACRS	
Investment Tax Credit	0.0	%

Financial structure

Type of Security	% of Total	Current Dollar Cost, %	Current Dollar Ret, %	Constant Dollar Cost, %	Constant Dollar Ret, %
Debt	80	9.0	7.2	5.8	4.6
Preferred Stock	0	3.0	0.0	0.0	0.0
Common Stock	20	20.0	4.0	16.5	3.3
Discount rate (cost of capital)			11.2		7.9

Inflation rate, % per year	3.0
Real Escalation rates (over inflation)	
Fuel, % per year	-1.1
Operating & Maintenance, % per year	0.0

C. COST OF ELECTRICITY

The approach to determining the cost of electricity is based upon the methodology described in the Technical Assessment Guide, published by the Electric Power Research Institute. The cost of electricity is stated in terms of 10th year levelized dollars.

	Current $	Constant $
Levelizing Factors		
Capital Carrying Charge, 10th yr	0.179	0.148
Fuel, 10th year	1.091	0.948
Operating & Maintenance, 10th yr	1.151	1.000

Cost of Electricity - Levelized	mills/kWh	mills/kWh
Capital Charges	42.5	35.3
Fuel Costs	9.7	8.5
Consumables	0.2	0.2
Fixed Operating & Maintenance	7.2	6.2
Variable Operating & Maintenance	1.3	1.1
By-product	-2.2	-1.9
Total Cost of Electricity	58.7	49.3

Hydrogen Turbine - CO_2 Capture

Hydrogen from Steam Methane Reforming (SMR)

Hydrogen Turbine Cycle - NATURAL GAS **413 MW POWER PLANT**

1st Q 2002 Dollar

Total Plant Investment		PROCESS	PROCESS	COST, K$
AREA NO	PLANT SECTION DESCRIPTION	CONT, %	CONT, K$	W/O CONT
	Gas Turbine	5	$2,649	$52,986
	Steam Cycle	5	$2,436	$48,721
	Hydrogen Production	5	$8,375	$167,505
	CO2 Compressor	0	$0	$13,605
18	Water Systems	0	$0	$12,859
30	Civil/Structural/Architectural	0	$0	$25,174
40	Piping	0	$0	$12,859
50	Control/ Instrumentation	0	$0	$14,489
60	Electrical	0	$0	$28,615
	Subtotal, Process Plant Cost			$376,813
Engineering Fees				$37,681
Process Contingency (Using cont. listed)				$13,461
Project Contingency,	15 % Proc Plt & Gen Plt Fac			$56,522
	Total Plant Cost (TPC)			$484,476
Plant Construction Period,	2.0 Years (1 or more)			
Construction Interest Rate,	11.2 %			
Adjustment for Interest and Inflation				$19,234
	Total Plant Investment (TPI)			$503,710
Prepaid Royalties				$1,884
Initial Catalyst and Chemical Inventory				$4
Startup Costs				$20,643
Spare Parts				$2,422
Working Capital				$17,602
Land,	100 Acres @ $1500/acre			$150
	Total Capital Requirement (TCR)			$546,415
		$/kW		1323

ANNUAL OPERATING COSTS

Capacity Factor =	85	%				
			UNIT $		ANNUAL	
Consumables			UNIT $		ANNUAL	
COST ITEM	QUANTITY		PRICE		COST, K$	
Natural Gas	86,047	MMBtu/D	$3.24	$/MMBtu	$86,538
Water	8,175	T/d	$0.19	/T	$482
Plant Labor					
Oper Labor (incl benef)	10	Men/shift	$34.00	/Hr.	$2,970
Supervision & Clerical					$2,170
Maintenance Costs	2.2%				$10,658
Insurance & Local Taxes					$9,690
Other Operating Costs					$723
Total Operating Costs					$113,232

BASES AND ASSUMPTIONS

A. CAPITAL BASES AND DETAILS

	QUANTITY		UNIT $ PRICE		COST, K$
Initial Cat./Chem. Inventory					
Water	20,847	tons	$0.19	/T	$4
Total Catalyst and Chemical Inventory					$4
Startup costs					
Plant modifications,	2	% TPI			$10,074
Operating costs					$10,569
Total Startup Costs					$20,643
Working capital					
Fuel & Consumables inv	60	days supply			$16,829
Direct expenses	30	days			$773
Total Working Capital					$17,602

B. ECONOMIC ASSUMPTIONS

Project life	20	Years
Book life	20	Years
Tax life	20	Years
Federal and state income tax rate	38.0	%
Tax depreciation method	MACRS	
Investment Tax Credit	0.0	%

Financial structure

Type of Security	% of Total	Current Dollar Cost, %	Current Dollar Ret, %	Constant Dollar Cost, %	Constant Dollar Ret, %
Debt	80	9.0	7.2	5.8	4.6
Preferred Stock	0	0.2	0.0	0.0	0.0
Common Stock	20	20.0	4.0	16.5	3.3
Discount rate (cost of capital)			11.2		7.9

Inflation rate, % per year	3.0
Real Escalation rates (over inflation)	
Fuel, % per year	0.2
Operating & Maintenance, % per year	0.0

C. COST OF ELECTRICITY

The approach to determining the cost of electricity is based upon the methodology described in the Technical Assessment Guide, published by the Electric Power Research Institute. The cost of electricity is stated in terms of 10th year levelized dollars.

Levelizing Factors	Current $	Constant $
Capital Carrying Charge, 10th yr	0.179	0.148
Fuel, 10th year	1.162	1.010
Operating & Maintenance, 10th yr	1.151	1.000

Cost of Electricity - Levelized	mills/kWh	mills/kWh
Capital Charges	31.8	26.4
Fuel Costs	32.7	28.4
Consumables	0.2	0.2
Fixed Operating & Maintenance	8.3	7.2
Variable Operating & Maintenance	1.5	1.3
By-product	0.0	0.0
Total Cost of Electricity	74.5	63.5

Hydrogen Turbine - CO_2 Capture

Destec High Pressure (E-Gas™) / HGCU / HSD

H2 TURBINE COAL (DESTEC) **376 MW POWER PLANT**

1st Q 2002 Dollar

Total Plant Investment AREA NO	PLANT SECTION DESCRIPTION	PROCESS CONT, %	PROCESS CONT, K$	COST, K$ W/O CONT
11	Coal Slurry Preparation	0	$0	$29,661
12	Oxygen Plant	0	$0	$62,455
12	Destec Gasifier	5	$3,447	$68,947
14	Gas Conditioning	10	$765	$7,649
14	Transport Desulfurizer	15	$881	$5,871
14	Sulfuric Acid Plant	0	$0	$21,301
14	Hydrogen Separation Device	50	$5,407	$10,814
15	CO2 Compressor	0	$0	$31,670
15	H2 Compressor	0	$0	$6,478
15	Power Turbine	0	$0	$10,339
15	Gas Turbine + Steam Cycle System	5	$4,639	$92,785
15	HRSG/Steam Turbine	0	$0	$19,067
18	Water Systems	0	$0	$20,187
30	Civil/Structural/Architectural	0	$0	$22,756
40	Piping	0	$0	$20,187
50	Control/ Instrumentation	0	$0	$14,681
60	Electrical	0	$0	$31,932

Subtotal, Process Plant Cost		$476,781
Engineering Fees		$47,678
Process Contingency (Using cont. listed)		$15,139
Project Contingency,	15 % Proc Plt & Gen Plt Fac	$71,517
Total Plant Cost (TPC)		$611,116
Plant Construction Period,	4.0 Years (1 or more)	
Construction Interest Rate,	11.2 %	
Adjustment for Interest and Inflation		$76,713
Total Plant Investment (TPI)		$687,829
Prepaid Royalties		$2,384
Initial Catalyst and Chemical Inventory		$132
Startup Costs		$16,375
Spare Parts		$3,056
Working Capital		$6,922
Land,	200 Acres @ $1500/acre	$300
Total Capital Requirement (TCR)		$716,998
	$/kW	1909

ANNUAL OPERATING COSTS

Capacity Factor = 85 %

COST ITEM	QUANTITY		UNIT $ PRICE		ANNUAL COST, K$
Coal (Illinois #6)	3,570	T/D	$24.36	/T	$26,981
Consumable Materials					
Water	3,388	T/D	$0.19	/T	$200
HGCU Sorbent	0.04	T/D	$6,000	/T	$71
Nahcolite	2.3	T/D	$275	/T	$196
Ash/Sorbent Disposal Costs	436	T/D	$8.00	/T	$1,082
Plant Labor					
Oper Labor (incl benef)	15	Men/shift	$34.00	/Hr.	$4,455
Supervision & Clerical					$2,950
Maintenance Costs 2.2%					$13,445
Royalties					$270
Other Operating Costs					$983
Total Operating Costs					$50,633
By-Product Credits					
Sulfuric Acid	275.9	T/D	$68.00	/T	$5,820
___________________	0.0	T/D	$0.00	/T	$0
___________________	0.0	T/D	$0.00	/T	$0
___________________	0.0	T/D	$0.00	/T	$0
Total By-Product Credits					$5,820
Net Operating Costs					$44,813

BASES AND ASSUMPTIONS

A. CAPITAL BASES AND DETAILS

	QUANTITY	UNIT $ PRICE	COST, K$
Initial Cat./Chem. Inventory			
Water	86387 T	$0.19 /T	$16
HGCU Sorbent	17 T	$6,000 /T	$100
Nahcolite	59 T	$275 /T	$16
Total Catalyst and Chemical Inventory			$132
Startup costs			
Plant modifications,	2 % TPI		$13,757
Operating costs			$1,966
Fuel			$652
Total Startup Costs			$16,375
Working capital			
Fuel & Consumables inv	60 days supply		$5,308
By-Product inventory	30 days supply		$563
Direct expenses	30 days		$1,051
Total Working Capital			$6,922

B. ECONOMIC ASSUMPTIONS

Project life	20 Years
Book life	20 Years
Tax life	20 Years
Federal and state income tax rate	38.0 %
Tax depreciation method	MACRS
Investment Tax Credit	0.0 %

Financial structure

Type of Security	% of Total	Current Dollar Cost, %	Current Dollar Ret, %	Constant Dollar Cost, %	Constant Dollar Ret, %
Debt	80	9.0	7.2	5.8	4.6
Preferred Stock	0	3.0	0.0	0.0	0.0
Common Stock	20	20.0	4.0	16.5	3.3
Discount rate (cost of capital)			11.2		7.9

Inflation rate, % per year	3.0
Real Escalation rates (over inflation)	
Fuel, % per year	-1.1
Operating & Maintenance, % per year	0.0

C. COST OF ELECTRICITY

The approach to determining the cost of electricity is based upon the methodology described in the Technical Assessment Guide, published by the Electric Power Research Institute. The cost of electricity is stated in terms of 10th year levelized dollars.

	Current $	Constant $
Levelizing Factors		
Capital Carrying Charge, 10th yr	0.179	0.148
Fuel, 10th year	1.091	0.948
Operating & Maintenance, 10th yr	1.151	1.000

Cost of Electricity - Levelized	mills/kWh	mills/kWh
Capital Charges	45.9	38.1
Fuel Costs	10.5	9.1
Consumables	0.6	0.6
Fixed Operating & Maintenance	7.7	6.7
Variable Operating & Maintenance	1.4	1.2
By-product	-2.4	-2.1
Total Cost of Electricity	63.8	53.6

Hybrid Cycles (Turbine / SOFC)

Natural Gas Hybrid Turbine / SOFC Cycle

Natural Gas HAT **19 MW POWER PLANT**

1st Q 2002 Dollar

Total Plant Investment AREA NO	PLANT SECTION DESCRIPTION	PROCESS CONT, %	PROCESS CONT, K$	COST, K$ W/O CONT
15	SOFC Generator Equipment	0	$0	$9,238
15	SOFC Power Conditioning Equipment	0	$0	$2,096
15	Gas Turbine Equipment	0	$0	$4,134
18	Balance of Plant Equipment	0	$0	$5,074
	Subtotal, Process Plant Cost			$20,543
Project Management and Engineering Fees				$940
Site Preparation				$431
Overhead and Profit				$5,701
	Total Plant Cost (TPC)			$27,615
Spare Parts, Startup, and Land Allowance				$431
	Total Capital Requirement (TCR)			$28,046
		$/kW		1476

ANNUAL OPERATING COSTS

Capacity Factor = 85 %

COST ITEM		QUANTITY		UNIT $ PRICE		ANNUAL COST, K$
Natural Gas		2,536	1000 SCF/day	$3.20	/1000 SCF	$2,518
Plant Labor						
Oper Labor (incl benef)		1	Men/shift	$34.00	/Hr.	$297
Supervision & Clerical						$94
Maintenance Costs	$ 0.01	per GT kWe				$40
Royalties						$0
Other Operating Costs						$31
Total Operating Costs						$2,980
By-Product Credits						
		0.0	T/D	$0.00	/T	$0
____________________		0.0	T/D	$0.00	/T	$0
____________________		0.0	T/D	$0.00	/T	$0
____________________		0.0	T/D	$0.00	/T	$0
Total By-Product Credits						$0
Net Operating Costs						$2,980

B. ECONOMIC ASSUMPTIONS

Project life	20	Years
Book life	20	Years
Tax life	20	Years
Federal and state income tax rate	38.0	%
Tax depreciation method	MACRS	
Investment Tax Credit	0.0	%

Financial structure

Type of Security	% of Total	Current Dollar Cost, %	Current Dollar Ret, %	Constant Dollar Cost, %	Constant Dollar Ret, %
Debt	80	9.0	7.2	5.8	4.6
Preferred Stock	0	3.0	0.0	0.0	0.0
Common Stock	20	20.0	4.0	16.5	3.3
Discount rate (cost of capital)			11.2		7.9

Inflation rate, % per year	3.0
Real Escalation rates (over inflation)	
Fuel, % per year	0.2
Operating & Maintenance, % per year	0.0

C. COST OF ELECTRICITY

The approach to determining the cost of electricity is based upon the methodology described in the Technical Assessment Guide, published by the Electric Power Research Institute. The cost of electricity is stated in terms of 10th year levelized dollars.

Levelizing Factors	Current $	Constant $
Capital Carrying Charge, 10th yr	0.179	0.148
Fuel, 10th year	1.162	1.010
Operating & Maintenance, 10th yr	1.151	1.000

Cost of Electricity - Levelized	mills/kWh	mills/kWh
Capital Charges	35.5	29.4
Fuel Costs	20.7	18.0
Consumables	0.0	0.0
Fixed Operating & Maintenance	3.2	2.8
Variable Operating & Maintenance	3.8	3.3
By-product	0.0	0.0
Total Cost of Electricity	63.1	53.4

Hybrid Cycles (Turbine / SOFC)

Destec (E-Gas™) / HGCU / “G” GT / No CO_2 Capture

Destec Hybrid HGCU/ SOFC IGCC **644 MW POWER PLANT**

(no CO2 Capture) 1st Q 2002 Dollar

Total Plant Investment AREA NO	PLANT SECTION DESCRIPTION	PROCESS CONT, %	PROCESS CONT, K$	COST, K$ W/O CONT
11	Coal Slurry Preparation	0	$0	$32,927
12	Oxygen Plant	0	$0	$60,463
12	Destec Gasifier	5	$3,659	$73,186
12	Misc. Compressors (Recycle, Quench, Air Boost	5	$422	$8,445
14	Gas Conditioning	10	$1,906	$19,061
14	Transport Desulfurizer	15	$1,533	$10,221
14	Sulfuric Acid Plant	0	$0	$23,331
15	Solid Oxide Fuel Cell	0	$0	$177,120
15	Gas Turbine System	5	$2,905	$58,105
15	HRSG/Steam Turbine	5	$2,731	$54,621
18	Water Systems	0	$0	$18,112
30	Civil/Structural/Architectural	0	$0	$32,084
40	Piping	0	$0	$18,112
50	Control/ Instrumentation	0	$0	$20,699
60	Electrical	0	$0	$45,021

Subtotal, Process Plant Cost		$651,509
Engineering Fees		$65,151
Process Contingency (Using cont. listed)		$13,157
Project Contingency,	15 % Proc Plt & Gen Plt Fac	$97,726
Total Plant Cost (TPC)		$827,543
Plant Construction Period,	4.0 Years (1 or more)	
Construction Interest Rate,	11.2 %	
Adjustment for Interest and Inflation		$103,881
Total Plant Investment (TPI)		$931,424
Prepaid Royalties		$3,258
Initial Catalyst and Chemical Inventory		$430
Startup Costs		$21,871
Spare Parts		$4,138
Working Capital		$8,085
Land,	200 Acres	$1,300
Total Capital Requirement (TCR)		$970,505
	$/kW	1508

ANNUAL OPERATING COSTS

Capacity Factor = 85 %

COST ITEM		QUANTITY		UNIT $ PRICE		ANNUAL COST, K$
Coal (Illinois #6)		4,145	T/D	$24.36	/T	$31,324
Consumable Materials						
Water		2,931	T/D	$0.19	/T	$173
HGCU Sorbent		0.15	T/D	$6,000	/T	$285
Nahcolite		2.3	T/D	$275	/T	$196
Ash/Sorbent Disposal Costs		617	T/D	$8.00	/T	$1,531
Plant Labor						
Oper Labor (incl benef)		15	Men/shift	$34.00	/Hr.	$4,455
Supervision & Clerical						$3,521
Maintenance Costs	2.2%					$18,206
Royalties						$313
Other Operating Costs						$1,174
Total Operating Costs						$61,179
By-Product Credits						
Sulfuric Acid		316.7	T/D	$68.00	/T	$6,681
___________________		0.0	T/D	$0.00	/T	$0
___________________		0.0	T/D	$0.00	/T	$0
___________________		0.0	T/D	$0.00	/T	$0
Total By-Product Credits						$6,681
Net Operating Costs						$54,497

BASES AND ASSUMPTIONS

A. CAPITAL BASES AND DETAILS

	QUANTITY		UNIT $ PRICE		COST, K$
Initial Cat./Chem. Inventory					
Water	74751	T	$0.19	/T	$14
HGCU Sorbent	67	T	$6,000	/T	$399
Nahcolite	59	T	$275	/T	$16
Total Catalyst and Chemical Inventory					$430
Startup costs					
Plant modifications,	2	% TPI			$18,628
Operating costs					$2,486
Fuel					$757
Total Startup Costs					$21,871
Working capital					
Fuel & Consumables inv	60	days supply			$6,184
By-Product inventory	30	days supply			$646
Direct expenses	30	days			$1,254
Total Working Capital					$8,085

B. ECONOMIC ASSUMPTIONS

Project life	20	Years
Book life	20	Years
Tax life	20	Years
Federal and state income tax rate	38.0	%
Tax depreciation method	MACRS	
Investment Tax Credit	0.0	%

Financial structure

Type of Security	% of Total	Current Dollar Cost, %	Current Dollar Ret, %	Constant Dollar Cost, %	Constant Dollar Ret, %
Debt	80	9.0	7.2	5.8	4.6
Preferred Stock	0	3.0	0.0	0.0	0.0
Common Stock	20	20.0	4.0	16.5	3.3
Discount rate (cost of capital)			11.2		7.9

Inflation rate, % per year	3.0
Real Escalation rates (over inflation)	
Fuel, % per year	-1.1
Operating & Maintenance, % per year	0.0

C. COST OF ELECTRICITY

The approach to determining the cost of electricity is based upon the methodology described in the Technical Assessment Guide, published by the Electric Power Research Institute. The cost of electricity is stated in terms of 10th year levelized dollars.

Levelizing Factors	Current $	Constant $
Capital Carrying Charge, 10th yr	0.179	0.148
Fuel, 10th year	1.091	0.948
Operating & Maintenance, 10th yr	1.151	1.000

Cost of Electricity - Levelized	mills/kWh	mills/kWh
Capital Charges	36.3	30.1
Fuel Costs	7.1	6.2
Consumables	0.5	0.5
Fixed Operating & Maintenance	5.6	4.9
Variable Operating & Maintenance	1.0	0.9
By-product	-1.6	-1.4
Total Cost of Electricity	48.9	41.1

Hybrid Cycles (Turbine / SOFC)

Destec High Pressure (E-Gas^{TM}) / HGCU / "G" GT / CO_2 Capture

Hybrid DESTEC HGCU/ SOFC **755 MW POWER PLANT**

(Sequesters CO2) 1st Q 2002 Dollar

Total Plant Investment AREA NO	 PLANT SECTION DESCRIPTION	PROCESS CONT, %	PROCESS CONT, K$	COST, K$ W/O CONT
11	Coal Slurry Preparation	0	$0	$40,290
12	Oxygen Plant	0	$0	$109,383
12	Destec Gasifier	5	$4,347	$86,934
12	Misc. Compressors (Recycle, Quench, Air Boost)	5	$50	$1,000
14	Gas Conditioning	10	$1,040	$10,400
14	Transport Desulfurizer	15	$1,049	$6,996
14	Sulfuric Acid Plant	0	$0	$28,431
14	Hydrogen Separation Device	50	$4,021	$8,041
15	H2/ CO2 Compressors	0	$0	$52,131
15	Gas Expanders	0	$0	$14,165
15	Solid Oxide Fuel Cell	0	$0	$259,280
15	Gas Turbine System	5	$2,680	$53,595
15	HRSG/Steam Turbine	5	$3,240	$64,798
18	Water Systems	0	$0	$25,741
30	Civil/Structural/Architectural	0	$0	$45,598
40	Piping	0	$0	$25,741
50	Control/ Instrumentation	0	$0	$29,418
60	Electrical	0	$0	$63,984

Subtotal, Process Plant Cost		$925,925
Engineering Fees		$92,592
Process Contingency (Using cont. listed)		$16,426
Project Contingency,	15 % Proc Plt & Gen Plt Fac	$138,889
Total Plant Cost (TPC)		$1,173,833
Plant Construction Period,	4.0 Years (1 or more)	
Construction Interest Rate,	11.2 %	
Adjustment for Interest and Inflation		$147,351
Total Plant Investment (TPI)		$1,321,183
Prepaid Royalties		$4,630
Initial Catalyst and Chemical Inventory		$195
Startup Costs		$30,701
Spare Parts		$5,869
Working Capital		$10,651
Land, 200 Acres		$1,300
Total Capital Requirement (TCR)		$1,374,529
	$/kW	1822

ANNUAL OPERATING COSTS

Capacity Factor = 85 %

COST ITEM		QUANTITY		UNIT $ PRICE		ANNUAL COST, K$
Coal (Illinois #6)		5,530	T/D	$24.36	/T	$41,792
Consumable Materials						
Water		5,059	T/D	$0.19	/T	$298
HGCU Sorbent		0.06	T/D	$6,000	/T	$110
Nahcolite		2.3	T/D	$275	/T	$196
Ash/Sorbent Disposal Costs		832	T/D	$8.00	/T	$2,066
Plant Labor						
Oper Labor (incl benef)		15	Men/shift	$34.00	/Hr.	$4,455
Supervision & Clerical						$4,436
Maintenance Costs	2.2%					$25,824
Royalties						$418
Other Operating Costs						$1,479
Total Operating Costs						$81,074
By-Product Credits						
Sulfuric Acid		427.3	T/D	$68.00	/T	$9,014
___________________		0.0	T/D	$0.00	/T	$0
___________________		0.0	T/D	$0.00	/T	$0
___________________		0.0	T/D	$0.00	/T	$0
Total By-Product Credits						$9,014
Net Operating Costs						$72,060

BASES AND ASSUMPTIONS

A. CAPITAL BASES AND DETAILS

	QUANTITY		UNIT $ PRICE		COST, K$
Initial Cat./Chem. Inventory					
Water	129006	T	$0.19	/T	$25
HGCU Sorbent	26	T	$6,000	/T	$155
Nahcolite	59	T	$275	/T	$16
Total Catalyst and Chemical Inventory					$195
Startup costs					
Plant modifications,	2	% TPI			$26,424
Operating costs					$3,267
Fuel					$1,010
Total Startup Costs					$30,701
Working capital					
Fuel & Consumables inv	60	days supply			$8,199
By-Product inventory	30	days supply			$872
Direct expenses	30	days			$1,580
Total Working Capital					$10,651

B. ECONOMIC ASSUMPTIONS

Project life	20	Years
Book life	20	Years
Tax life	20	Years
Federal and state income tax rate	38.0	%
Tax depreciation method	MACRS	
Investment Tax Credit	0.0	%

Financial structure

Type of Security	% of Total	Current Dollar Cost, %	Current Dollar Ret, %	Constant Dollar Cost, %	Constant Dollar Ret, %
Debt	80	9.0	7.2	5.8	4.6
Preferred Stock	0	3.0	0.0	0.0	0.0
Common Stock	20	20.0	4.0	16.5	3.3
Discount rate (cost of capital)			11.2		7.9

Inflation rate, % per year	3.0
Real Escalation rates (over inflation)	
Fuel, % per year	-1.1
Operating & Maintenance, % per year	0.0

C. COST OF ELECTRICITY

The approach to determining the cost of electricity is based upon the methodology described in the Technical Assessment Guide, published by the Electric Power Research Institute. The cost of electricity is stated in terms of 10th year levelized dollars.

Levelizing Factors	Current $	Constant $
Capital Carrying Charge, 10th yr	0.179	0.148
Fuel, 10th year	1.091	0.948
Operating & Maintenance, 10th yr	1.151	1.000

Cost of Electricity - Levelized	mills/kWh	mills/kWh
Capital Charges	43.8	36.3
Fuel Costs	8.1	7.1
Consumables	0.5	0.5
Fixed Operating & Maintenance	6.4	5.5
Variable Operating & Maintenance	1.1	1.0
By-product	-1.8	-1.6
Total Cost of Electricity	58.1	48.8

<u>Hybrid Cycles (Turbine / SOFC)</u>

Destec (E-Gas™) / OTM / CGCU /
"G" GT / No CO_2 Capture

Case: OTM/SOFC Case Destec Cold Gas Cleanup Unit
Plant Size: 675.2 MW
Capacity Factor : 85 % **1st Quarter 2002 Dollar Base**

Capital Costs			**$ x 1000**
Installed Equipment Cost			$612,059
Process Contingency			$6,565
Project Contingency			$91,809
Engineering Fees			$61,206
	Subtotal, Process Plant Cost		**$771,639**
AFDC			$96,863
Plant Construction Period	4.0 Years		
Construction Interest Rate	11.2 %		
	Total Plant Investment (TPI)		**$868,502**
Prepaid Royalties			$3,060
Startup Costs			$20,500
Spare Parts			$3,858
Working Capital			$7,836
Land, 200	Acres		$1,300
	Total Capital Requirement (TCR)		**$905,057**
			1340 $/kW

ANNUAL OPERATING COSTS

COST ITEM	Quantity		Unit Price		Annual Cost, K$
Coal (Illinois #6)	4,311	T/D	$24.36	/T	$32,584
Consumable Materials					
Water	5,165	T/D	$0.19	/T	$304
MDEA Solvent	403.2	Lb/D	$1.45	/Lb	$218
Claus Catalyst	0.01	T/D	$470	/T	$2
SCOT Activated Alumina	15.9	Lb/D	$0.67	/Lb	$4
SCOT Cobalt Catalyst					$6
SCOT Chemicals					$19
Ash Disposal Costs	571	T/D	$8.00	/T	$1,417
Plant Labor					
Oper Labor (incl benef)	15	Men/shift	$34.00	/Hr.	$4,455
Supervision & Clerical					$3,374
Maintenance Costs	2.2%				$16,976
Royalties					$326
Other Operating Costs					$1,125
	SubTotal Operating Costs				$60,809
By-Product Credits					
Sulfur	106.0	T/D	$75.00	/T	$2,467
	0.0	T/D	$0.00	/T	$0
	Total By-Product Credits				$2,467
	Net Operating Costs				**$58,342**

CAPITAL BASES AND DETAILS

Startup costs		
Plant modifications,	2 % TPI	$17,370
Operating costs		$2,342
Fuel		$788
Total Startup Costs		$20,500
Working capital		
Fuel & Consumables inv	60 days supply	$6,396
By-Product inventory	30 days supply	$239
Direct expenses	30 days	$1,202
Total Working Capital		$7,836

ECONOMIC ASSUMPTIONS

Project life	20 Years
Book life	20 Years
Tax life	20 Years
Federal and state income tax rate	38.0 %
Tax depreciation method	ACRS
Investment Tax Credit	0.0 %

Financial structure

Type of Security	% of Total	Current Dollar Cost, %	Current Dollar Ret, %	Constant Dollar Cost, %	Constant Dollar Ret, %
Debt	80	9.0	7.2	5.8	4.6
Preferred Stock	0	3.0	0.0	0.0	0.0
Common Stock	20	20.0	4.0	16.5	3.3
Discount rate (cost of capital)			11.2		7.9

Inflation rate, % per year	3.0
Real Escalation rates (over inflation)	
Fuel, % per year	-1.1
Operating & Maintenance, % per year	0.0

COST OF ELECTRICITY

The approach to determining the cost of electricity is based upon the methodology described in the Technical Assessment Guide, published by the Electric Power Research Institute, The cost of electricity is stated in terms of 10th year levelized dollars.

Levelizing Factors	Current $	Constant $
Capital Carrying Charge, 10th yr	0.179	0.148
Fuel, 10th year	1.091	0.948
Operating & Maintenance, 10th yr	1.151	1.000

Cost of Electricity - Levelized	mills/kWh	mills/kWh
Capital Charges	32.2	26.7
Fuel Costs	7.1	6.1
Consumables	0.5	0.4
Fixed Operating & Maintenance	5.1	4.4
Variable Operating & Maintenance	0.9	0.8
By-product	-0.6	-0.5
Total Cost of Electricity	45.2	38.0

Humid Air Turbine (HAT)

Natural Gas / Pratt Whitney GT

Natural Gas HAT **319 MW POWER PLANT**

1st Q 2002 Dollar

Total Plant Investment AREA NO	PLANT SECTION DESCRIPTION	PROCESS CONT, %	PROCESS CONT, K$	COST, K$ W/O CONT
15	HAT Gas Turbine	10	$8,822	$88,224
15	HAT Heat Recovery	10	$2,399	$23,993
15	HAT Air Saturator	10	$740	$7,402
18	Water Systems	0	$0	$8,493
30	Civil/Structural/Architectural	0	$0	$16,627
40	Piping	0	$0	$8,493
50	Control/ Instrumentation	0	$0	$9,569
60	Electrical	0	$0	$18,900

Subtotal, Process Plant Cost		$181,701
Engineering Fees		$18,170
Process Contingency (Using cont. listed)		$11,962
Project Contingency,	15 % Proc Plt & Gen Plt Fac	$27,255
Total Plant Cost (TPC)		$239,088
Plant Construction Period,	3.0 Years (1 or more)	
Construction Interest Rate,	11.2 %	
Adjustment for Interest and Inflation		$19,486
Total Plant Investment (TPI)		$258,574
Prepaid Royalties		$909
Initial Catalyst and Chemical Inventory		$0
Startup Costs		$7,288
Spare Parts		$1,195
Working Capital		$10,178
Land, 100 Acres	@ $1500/acre	$150
Total Capital Requirement (TCR)		$278,293
	$/kW	873

ANNUAL OPERATING COSTS

Capacity Factor = 85 %

COST ITEM		QUANTITY		UNIT $ PRICE		ANNUAL COST, K$
Natural Gas		49,802	1000 SCF/day	$3.20	/1000 SCF	$49,443
Consumable Materials						
Water		6,485	T/D	$0.19	/T	$382
Ash/Sorbent Disposal Costs		0	T/D	$8.00	/T	$0
Plant Labor						
Oper Labor (incl benef)		10	Men/shift	$34.00	/Hr.	$2,970
Supervision & Clerical						$1,522
Maintenance Costs	2.2%					$5,260
Royalties						$494
Other Operating Costs						$507
Total Operating Costs						$60,580
By-Product Credits						
		0.0	T/D	$0.00	/T	$0
____________________		0.0	T/D	$0.00	/T	$0
Total By-Product Credits						$0
Net Operating Costs						$60,580

BASES AND ASSUMPTIONS

A. CAPITAL BASES AND DETAILS

	QUANTITY		UNIT $ PRICE		COST, K$
Initial Cat./Chem. Inventory					
Water	165378	T	$0.19	/T	$31
Total Catalyst and Chemical Inventory					$31
Startup costs					
Plant modifications,	2	% TPI			$5,171
Operating costs					$921
Fuel					$1,195
Total Startup Costs					$7,288
Working capital					
Fuel & Consumables inv	60	days supply			$9,636
By-Product inventory	30	days supply			$0
Direct expenses	30	days			$542
Total Working Capital					$10,178

B. ECONOMIC ASSUMPTIONS

Project life	20	Years
Book life	20	Years
Tax life	20	Years
Federal and state income tax rate	38.0	%
Tax depreciation method	MACRS	
Investment Tax Credit	0.0	%

Financial structure

Type of Security	% of Total	Current Dollar Cost, %	Current Dollar Ret, %	Constant Dollar Cost, %	Constant Dollar Ret, %
Debt	80	9.0	7.2	5.8	4.6
Preferred Stock	0	3.0	0.0	0.0	0.0
Common Stock	20	20.0	4.0	16.5	3.3
Discount rate (cost of capital)			11.2		7.9

Inflation rate, % per year	3.0
Real Escalation rates (over inflation)	
Fuel, % per year	0.2
Operating & Maintenance, % per year	0.0

C. COST OF ELECTRICITY

The approach to determining the cost of electricity is based upon the methodology described in the Technical Assessment Guide, published by the Electric Power Research Institute. The cost of electricity is stated in terms of 10th year levelized dollars.

	Current $	Constant $
Levelizing Factors		
Capital Carrying Charge, 10th yr	0.179	0.148
Fuel, 10th year	1.162	1.010
Operating & Maintenance, 10th yr	1.151	1.000

Cost of Electricity - Levelized	mills/kWh	mills/kWh
Capital Charges	21.0	17.4
Fuel Costs	24.2	21.0
Consumables	0.2	0.2
Fixed Operating & Maintenance	4.4	3.9
Variable Operating & Maintenance	5.2	4.5
By-product	0.0	0.0
Total Cost of Electricity	55.0	47.0

Humid Air Turbine (HAT)

Coal Syngas / Destec (E-Gas™) / CGCU / Pratt Whitney GT

Destec Coal IGHAT **407 MW POWER PLANT**

1st Q 2002 Dollar

Total Plant Investment AREA NO	PLANT SECTION DESCRIPTION	PROCESS CONT, %	PROCESS CONT, K$	COST, K$ W/O CONT
11	Coal Slurry Preparation	0	$0	$28,073
12	Oxygen Plant	0	$0	$46,460
12	Destec Gasifier	5	$1,378	$27,555
12	Recycle Gas Compressor	0	$0	$1,914
12	Syngas Cooler/ Fuel Reheater/ Cyclone	0	$0	$3,881
14	Low Temperature Gas Treatment	0	$0	$9,911
14	MDEA/Claus/SCOT	0	$0	$19,785
14	Clean Fuel Compressor	0	$0	$10,936
15	HAT Gas Turbine	10	$10,803	$108,031
15	HAT Heat Recovery	10	$2,770	$27,701
15	HAT Air Saturator	10	$740	$7,405
18	Water Systems	0	$0	$16,041
30	Civil/Structural/Architectural	0	$0	$18,082
40	Piping	0	$0	$16,041
50	Control/ Instrumentation	0	$0	$11,666
60	Electrical	0	$0	$25,374

Subtotal, Process Plant Cost		$378,855
Engineering Fees		$37,886
Process Contingency (Using cont. listed)		$15,691
Project Contingency,	15 % Proc Plt & Gen Plt Fac	$56,828
Total Plant Cost (TPC)		$489,261
Plant Construction Period,	4.0 Years (1 or more)	
Construction Interest Rate,	11.2 %	
Adjustment for Interest and Inflation		$61,417
Total Plant Investment (TPI)		$550,677
Prepaid Royalties		$1,894
Initial Catalyst and Chemical Inventory		$120
Startup Costs		$13,347
Spare Parts		$2,446
Working Capital		$6,131
Land, 200 Acres	@ $1500/acre	$300
Total Capital Requirement (TCR)		$574,915
	$/kW	1411

ANNUAL OPERATING COSTS

Capacity Factor = 85 %

COST ITEM		QUANTITY		UNIT $ PRICE		ANNUAL COST, K$
	Coal (Illinois #6)	3,300	T/D	$24.36	/T	$24,942
Consumable Materials						
	Water	13,274	T/D	$0.19	/T	$782
	MDEA Solvent	403.2	Lb/D	$1.45	/Lb	$181
	Claus Catalyst	0.01	T/D	$470	/T	$1
	SCOT Activated Alum	15.9	Lb/D	$0.67	/Lb	$3
	SCOT Cobalt Catalyst					$5
	SCOT Chemicals					$16
Ash/Sorbent Disposal Costs		322	T/D	$8.00	/T	$799
Plant Labor						
Oper Labor (incl benef)		15	Men/shift	$34.00	/Hr.	$4,455
Supervision & Clerical						$2,628
Maintenance Costs	2.2%					$10,764
Royalties						$249
Other Operating Costs						$876
Total Operating Costs						$45,704
By-Product Credits						
	Sulfur	81.6	T/D	$75.00	/T	$1,899
	___________________	0.0	T/D	$0.00	/T	$0
	___________________	0.0	T/D	$0.00	/T	$0
	___________________	0.0	T/D	$0.00	/T	$0
Total By-Product Credits						$1,899
Net Operating Costs						$43,804

BASES AND ASSUMPTIONS

A. CAPITAL BASES AND DETAILS

	QUANTITY		UNIT $ PRICE		COST, K$
Initial Cat./Chem. Inventory					
Water	338490	T	$0.19	/T	$64
MDEA Solvent	10282	Lb	$1.45	/Lb	$15
Claus Catalyst	0.3	T	$470	/T	$0
SCOT Activated Alum	405	Lb	$0.67	/Lb	$0
SCOT Cobalt Catalyst					$16
SCOT Chemicals					$24
Total Catalyst and Chemical Inventory					$120
Startup costs					
Plant modifications,	2	% TPI			$11,014
Operating costs					$1,730
Fuel					$603
Total Startup Costs					$13,347
Working capital					
Fuel & Consumables inv	60	days supply			$5,011
By-Product inventory	30	days supply			$184
Direct expenses	30	days			$936
Total Working Capital					$6,131

B. ECONOMIC ASSUMPTIONS

Project life	20	Years
Book life	20	Years
Tax life	20	Years
Federal and state income tax rate	38.0	%
Tax depreciation method	MACRS	
Investment Tax Credit	0.0	%

Financial structure

Type of Security	% of Total	Current Dollar Cost, %	Current Dollar Ret, %	Constant Dollar Cost, %	Constant Dollar Ret, %
Debt	80	9.0	7.2	5.8	4.6
Preferred Stock	0	3.0	0.0	0.0	0.0
Common Stock	20	20.0	4.0	16.5	3.3
Discount rate (cost of capital)			11.2		7.9

Inflation rate, % per year	3.0
Real Escalation rates (over inflation)	
Fuel, % per year	-1.1
Operating & Maintenance, % per year	0.0

C. COST OF ELECTRICITY

The approach to determining the cost of electricity is based upon the methodology described in the Technical Assessment Guide, published by the Electric Power Research Institute. The cost of electricity is stated in terms of 10th year levelized dollars.

	Current $	Constant $
Levelizing Factors		
Capital Carrying Charge, 10th yr	0.179	0.148
Fuel, 10th year	1.091	0.948
Operating & Maintenance, 10th yr	1.151	1.000

Cost of Electricity - Levelized	mills/kWh	mills/kWh
Capital Charges	33.9	28.1
Fuel Costs	9.0	7.8
Consumables	0.7	0.6
Fixed Operating & Maintenance	6.1	5.3
Variable Operating & Maintenance	1.1	0.9
By-product	-0.7	-0.6
Total Cost of Electricity	50.1	42.1

Appendix C - FUEL COMPOSITION

Ambient conditions:

Temperature	59 F
Pressure	14.7 psia
Relative Humidity	60%

Coal Analysis

Proximate Analysis	(Wt. %)	(Wt. % dry)	Ultimate Analysis	(Wt. %)	(Wt. % dry)
Moisture	11.12		Moisture	11.12	
Ash	9.70	10.91	Carbon	63.75	71.72
Volatiles	34.99	39.37	Hydrogen	4.50	5.06
Fixed carbon	44.19	49.72	Nitrogen	1.25	1.41
Total	100.00	100.00	Chlorine	0.29	0.33
			Sulfur	2.51	2.82
HHV (Btu/lb)	11,666	13,126	Ash	9.70	10.91
			Oxygen	6.88	7.75
			Total	100.00	100.00

NATURAL GAS – assumed 100% Methane for ASPEN simulation.

APPENDIX D – VISION 21 GOALS

Goals

The primary goal of the Vision 21 Program is to effectively remove all environmental concerns associated with the use of fossil fuels for producing electricity, transportation fuels, and high-value chemicals. This goal is to be accomplished at competitive costs. The specific performance targets, costs, and timing for Vision 21 plants are shown below.

Vision 21 Energy Plant Performance Targets

Efficiency - Electricity Generation:

- 60% for coal-based systems (HHV)
- 75% for natural gas-based systems (LHV)

Efficiency - Combined Heat & Power:

- Overall thermal efficiency above 85% (HHV); also meets efficiency goals for electricity (based on fuel)

Efficiency - Fuels Only Plant:

- 75% feedstock utilization efficiency (LHV) when producing fuels such as H_2 or liquid transportation fuels alone from coal

Environmental:

- Atmospheric release of near zero emissions of
  - sulfur
  - nitrogen oxides
  - particulate matter
  - trace elements and organic compounds or liquid transportation fuels alone from coal
- 40-50% reduction of CO_2 emissions by efficiency improvement
  - 100% reduction with sequestration

Costs:

- Aggressive targets for capital and operating costs and RAM (reliability, availability, and maintenance). Cost of electricity 10% lower than conventional systems
- Products of Vision 21 plants must be cost-competitive with other energy subsystems with comparable environmental performance, including specific carbon emissions

Timing:

- Major benefits from improved technologies begin by 2005
- Designs for most Vision 21 subsystems and modules available by 2012
- Vision 21 commercial plant designs available by 2015

Cost and Performance Baseline for Fossil Energy Plants

DOE/NETL-2007/1281

Volume 1: Bituminous Coal and Natural Gas to Electricity

Final Report (Original Issue Date, May 2007)

Revision 1, August 2007

Disclaimer

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NETL Viewpoint

Background

The goal of Fossil Energy Research, Development and Demonstration (RD&D) is to ensure the availability of ultra-clean ("zero" emissions), abundant, low-cost, domestic electricity and energy (including hydrogen) to fuel economic prosperity and strengthen energy security. A broad portfolio of technologies is being developed within the Clean Coal Program to accomplish this objective. Ever increasing technological enhancements are in various stages of the research "pipeline," and multiple paths are being pursued to create a portfolio of promising technologies for development, demonstration, and eventual deployment. The technological progress of recent years has created a remarkable new opportunity for coal. Advances in technology are making it possible to generate power from fossil fuels with great improvements in the efficiency of energy use while at the same time significantly reducing the impact on the environment, including the long-term impact of fossil energy use on the Earth's climate. The objective of the Clean Coal RD&D Program is to build on these advances and bring these building blocks together into a new, revolutionary concept for future coal-based power and energy production.

Objective

To establish baseline performance and cost estimates for today's fossil energy plants, it is necessary to look at the current state of technology. Such a baseline can be used to benchmark the progress of the Fossil Energy RD&D portfolio. This study provides an accurate, independent assessment of the cost and performance for Pulverized Coal Combustion (PC), Integrated Gasification Combined Cycles (IGCC), and Natural Gas Combined Cycles (NGCC), all with and without carbon dioxide capture and storage assuming that the plants use technology available today.

Approach

The power plant configurations analyzed in this study were modeled using the ASPEN Plus modeling program. Performance and process limits were based upon published reports, information obtained from vendors and users of the technology, cost and performance data from design/build utility projects, and/or best engineering judgment. Capital and operating costs were estimated by WorleyParsons based on simulation results and through a combination of existing vendor quotes, scaled estimates from previous design/build projects, or a combination of the two. O&M costs and the cost for transporting, storing and monitoring CO_2 in the cases with carbon capture were also estimated based on reference data and scaled estimates. Levelized cost of electricity (LCOE) was determined for all plants assuming investor owned utility financing. The initial results of this analysis were subjected to a significant peer review by industry experts, academia and government research and regulatory agencies. Based on the feedback from these experts, the report was updated both in terms of technical content and revised costs.

Results

This independent assessment of fossil energy plant cost and performance is considered to be the most comprehensive set of publicly available data to date. While input was sought from various technology vendors, the final assessment of performance and cost was determined independently, and may not represent the view of the technology vendors. The extent of collaboration with technology vendors varied from case to case, with minimal or no collaboration obtained from some vendors. Selection of system components and plant configurations from the range of potential options and the current rapid escalation in labor and material costs made it a challenge to develop state-of-the-art configurations and cost estimates. The rigorous expert technical review and systematic use of existing vendor quotes and project design/build data to develop the cost estimates in this report are believed to provide the most up-to-date performance and costs available in the public literature. Highlights of the study are the following:

- Coal-based plants using today's technology are capable of producing electricity at relatively high efficiencies of about 39%, HHV (without capture) on bituminous coal and at the same time meet or exceed current environmental requirements for criteria pollutants.

- Capital cost (total plant cost) for the non-capture plants are as follows: NGCC, \$554/kW; PC, \$1,562/kW (average); IGCC, \$1,841/kW (average). With capture, capital costs are: NGCC, \$1,172/kW; PC, \$2,883/kW (average); IGCC, \$2,496/kW (average).

- At fuel costs of \$1.80/ton of coal and \$6.75/MMBtu of natural gas, the 20-year levelized cost of electricity for the non-capture plants are: 64 mills/kWh (average) for PC, 68 mills/kWh for NGCC, and 78 mills/kWh (average) for IGCC.

- When today's technology for carbon capture and sequestration is integrated into these new power plants, the resultant 20-year levelized COE including the cost of CO_2 transport, storage and monitoring is: 97 mills/kWh for NGCC; 106 mills/kWh (average) for IGCC; and 117 mills/kWh (average) for PC. The cost of transporting CO_2 50 miles for storage in a geologic formation with over 30 years of monitoring is estimated to add about 4 mills/kWh. This represents only about 10% of the total carbon capture and sequestration costs.

- A sensitivity study on natural gas price reveals that the COE for IGCC is equal to that of NGCC at \$7.73/MMBtu, and for PC, the COE is equivalent to NGCC at a gas price of \$8.87/MMBtu. In terms of capacity factor, when the NGCC drops below 60 percent, such as in a peaking application, the resulting COE is higher than that of an IGCC operating at baseload (80 percent capacity factor).

Fossil Energy RD&D is aimed at improving the performance and cost of clean coal power systems including the development of new approaches to capture and sequester greenhouse gases. Improved efficiencies and reduced costs are required to improve the competitiveness of these systems in today's market and regulatory environment as well as in a carbon constrained scenario. The results of this analysis provide a starting point from which to measure the progress of RD&D achievements.

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LIST OF EXHIBITS

ACKNOWLEDGEMENTS

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LIST OF ACRONYMS AND ABBREVIATIONS

AACE	Association for the Advancement of Cost Engineering
AC	Alternating current
AEO	Annual Energy Outlook
AGR	Acid gas removal
ANSI	American National Standards Institute
ASU	Air separation unit
BACT	Best available control technology
BEC	Bare erected cost
BFD	Block flow diagram
Btu	British thermal unit
Btu/h	British thermal unit per hour
Btu/kWh	British thermal unit per kilowatt hour
Btu/lb	British thermal unit per pound
Btu/scf	British thermal unit per standard cubic foot
CAAA	Clean Air Act Amendments of 1990
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CCF	Capital Charge Factor
CDR	Carbon Dioxide Recovery
CF	Capacity factor
CFM	Cubic feet per minute
CFR	Code of Federal Regulations
CGE	Cold gas efficiency
cm	Centimeter
CO_2	Carbon dioxide
COE	Cost of electricity
CoP	ConocoPhillips
COR	Contracting Officer's Representative
COS	Carbonyl sulfide
CRT	Cathode ray tube
CS	Carbon steel
CT	Combustion turbine
CTG	Combustion Turbine-Generator
CWT	Cold water temperature
dB	Decibel
DCS	Distributed control system
DI	De-ionized
Dia.	Diameter
DLN	Dry low NOx
DOE	Department of Energy
EAF	Equivalent availability factor

E-Gas™	ConocoPhillips gasifier technology
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EPC	Engineer/Procure/Construct
EPRI	Electric Power Research Institute
EPCM	Engineering/Procurement/Construction Management
EU	European Union
ESP	Electrostatic precipitator
FD	Forced draft
FERC	Federal Energy Regulatory Commission
FG	Flue gas
FGD	Flue gas desulfurization
FOAK	First of a kind
FRP	Fiberglass-reinforced plastic
ft	Foot, Feet
ft, w.g.	Feet of water gauge
GADS	Generating Availability Data System
gal	Gallon
gal/MWh	Gallon per megawatt hour
GDP	Gross domestic product
GEE	GE Energy
gpm	Gallons per minute
gr/100 scf	grains per one hundred standard cubic feet
GT	Gas turbine
h	Hour
H_2	Hydrogen
H_2SO_4	Sulfuric acid
HAP	Hazardous air pollutant
HCl	Hydrochloric acid
Hg	Mercury
HDPE	High density polyethylene
HHV	Higher heating value
hp	Horsepower
HP	High pressure
HRSG	Heat recovery steam generator
HSS	Heat stable salts
HVAC	Heating, ventilating, and air conditioning
HWT	Hot water temperature
Hz	Hertz
ICR	Information Collection Request
ID	Induced draft
IGVs	Inlet guide vanes
In. H_2O	Inches water

In. Hga	Inches mercury (absolute pressure)
In. W.C.	Inches water column
IEEE	Institute of Electrical and Electronics Engineers
IGCC	Integrated gasification combined cycle
IGV	Inlet guide vanes
IOU	Investor-owned utility
IP	Intermediate pressure
IPM	Integrated Planning Model
IPP	Independent power producer
ISO	International Standards Organization
KBR	Kellogg, Brown and Root, a subsidiary of Halliburton
kg/GJ	Kilogram per gigajoule
kg/h	Kilogram per hour
kJ	Kilojoules
kJ/h	Kilojoules per hour
kJ/kg	Kilojoules per kilogram
KO	Knockout
kPa	Kilopascal absolute
kV	Kilovolt
kW	Kilowatt
kWe	Kilowatts electric
kWh	Kilowatt-hour
LAER	Lowest Achievable Emission Rate
lb	Pound
lb/h	Pounds per hour
lb/ft^2	Pounds per square foot
lb/MMBtu	Pounds per million British thermal units
lb/MWh	Pounds per megawatt hour
lb/TBtu	Pounds per trillion British thermal units
LCOE	Levelized cost of electricity
LF_{Fn}	Levelization factor for category n fixed operating cost
LF_{Vn}	Levelization factor for category n variable operating cost
LGTI	Louisiana Gasification Technology, Inc.
LHV	Lower heating value
LNB	Low NOx burner
LP	Low pressure
lpm	Liters per minute
m	Meters
m/min	Meters per minute
m^3/min	Cubic meter per minute
MAF	Moisture and Ash Free
MCR	Maximum continuous rate
MDEA	Methyldiethanolamine

MEA	Monoethanolamine
MHz	Megahertz
MJ/Nm^3	Megajoule per normal cubic meter
MMBtu	Million British thermal units (also shown as 10^6 Btu)
MMBtu/h	Million British thermal units (also shown as 10^6 Btu) per hour
MMkJ	Million kilojoules (also shown as 10^6 kJ)
MMkJ/h	Million kilojoules (also shown as 10^6 kJ) per hour
MNQC	Multi Nozzle Quiet Combustor
MPa	Megapascals
MVA	Mega volt-amps
MWe	Megawatts electric
MWh	Megawatt-hour
MWt	Megawatts thermal
N/A	Not applicable
NAAQS	National Ambient Air Quality Standards
NEMA	National Electrical Manufacturers Association
NERC	North American Electric Reliability Council
NETL	National Energy Technology Laboratory
NFPA	National Fire Protection Association
NGCC	Natural gas combined cycle
Nm^3	Normal cubic meter
NOx	Oxides of nitrogen
NSPS	New Source Performance Standards
NSR	New Source Review
O&M	Operation and maintenance
OC_{Fn}	Category n fixed operating cost for the initial year of operation
OC_{Vnq}	Category n variable operating cost for the initial year of operation
OD	Outside diameter
OFA	Overfire air
OP/VWO	Over pressure/valve wide open
OSHA	Occupational Safety and Health Administration
OTR	Ozone transport region
PA	Primary air
PAC	Powdered activated carbon
PC	Pulverized coal
PF	Power Factor
PM	Particulate matter
PM_{10}	Particulate matter measuring 10 µm or less
POTW	Publicly Owned Treatment Works
ppm	Parts per million
ppmv	Parts per million volume
ppmvd	Parts per million volume, dry
PPS	Polyphenylensulfide

PRB	Powder River Basin coal region
PSA	Pressure Swing Adsorption
PSD	Prevention of Significant Deterioration
psia	Pounds per square inch absolute
psid	Pounds per square inch differential
psig	Pounds per square inch gage
PTFE	Teflon (Polytetrafluoroethylene)
Qty	Quantity
RDS	Research and Development Solutions, LLC
RH	Reheater
scfh	Standard cubic feet per hour
scfm	Standard cubic feet per minute
Sch.	Schedule
scmh	Standard cubic meter per hour
SCOT	Shell Claus Off-gas Treating
SCR	Selective catalytic reduction
SG	Specific gravity
SGC	Synthesis gas cooler
SGS	Sour gas shift
SIP	State implementation plan
SNCR	Selective non-catalytic reduction
SO_2	Sulfur dioxide
SOx	Oxides of sulfur
SRU	Sulfur recovery unit
SS	Stainless steel
SS Amine	SS Specialty Amine
STG	Steam turbine generator
TCR	Total capital requirement
TEWAC	Totally Enclosed Water-to-Air Cooled
TGTU	Tail gas treating unit
Tonne	Metric Ton (1000 kg)
TPC	Total plant cost
TPD	Tons per day
TPH	Tons per hour
TPI	Total plant investment
TS&M	Transport, storage and monitoring
V-L	Vapor Liquid portion of stream (excluding solids)
vol%	Volume percent
WB	Wet bulb
wg	Water gauge
wt%	Weight percent
$/MMBtu	Dollars per million British thermal units
$/MMkJ	Dollars per million kilojoule

EXECUTIVE SUMMARY

The objective of this report is to present an accurate, independent assessment of the cost and performance of fossil energy power systems, specifically integrated gasification combined cycle (IGCC), pulverized coal (PC), and natural gas combined cycle (NGCC) plants, using a consistent technical and economic approach that accurately reflects current market conditions for plants starting operation in 2010. This is Volume 1 of a three volume report. The three volume series consists of the following:

- Volume 1: Electricity production using bituminous coal for coal-based technologies
- Volume 2: Synthetic natural gas production and repowering using a variety of coal types
- Volume 3: Electricity production from low rank coal (PC and IGCC)

The cost and performance of the various fossil fuel-based technologies will most likely determine which combination of technologies will be utilized to meet the demands of the power market. Selection of new generation technologies will depend on many factors, including:

- Capital and operating costs
- Overall energy efficiency
- Fuel prices
- Cost of electricity (COE)
- Availability, reliability and environmental performance
- Current and potential regulation of air, water, and solid waste discharges from fossil-fueled power plants
- Market penetration of clean coal technologies that have matured and improved as a result of recent commercial-scale demonstrations under the Department of Energy's (DOE's) Clean Coal Programs

Twelve power plant configurations were analyzed as listed in Exhibit ES-1. The list includes six IGCC cases utilizing General Electric Energy (GEE), ConocoPhillips (CoP), and Shell gasifiers each with and without CO_2 capture; four PC cases, two subcritical and two supercritical, each with and without CO_2 capture; and two NGCC plants with and without CO_2 capture. Two additional cases were originally included in this study and involve production of synthetic natural gas (SNG) and the repowering of an existing NGCC facility using SNG. The two SNG cases were subsequently moved to Volume 2 of this report resulting in the discontinuity of case numbers (1-6 and 9-14). The two SNG cases are now cases 2 and 2a in Volume 2.

While input was sought from various technology vendors, the final assessment of performance and cost was determined independently, and may not represent the views of the technology vendors. The extent of collaboration with technology vendors varied from case to case, with minimal or no collaboration obtained from some vendors.

The methodology included performing steady-state simulations of the various technologies using the Aspen Plus (Aspen) modeling program. The resulting mass and energy balance data from the Aspen model were used to size major pieces of equipment. These equipment sizes formed the basis for cost estimating. Performance and process limits were based upon published reports, information obtained from vendors and users of the technology, performance data from design/build utility projects, and/or best engineering judgement. Capital and operating costs were estimated by WorleyParsons based on simulation results and through a combination of vendor quotes, scaled estimates from previous design/build projects, or a combination of the two. Baseline fuel costs for this analysis were determined using data from the Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2007. The first year (2010) costs used are $1.71/MMkJ ($1.80/MMBtu) for coal (Illinois No. 6) and $6.40/MMkJ ($6.75/MMBtu) for natural gas, both on a higher heating value (HHV) basis and in 2007 U.S. dollars.

Exhibit ES-1 Case Descriptions

Case	Unit Cycle	Steam Cycle, psig/°F/°F	Combustion Turbine	Gasifier/Boiler Technology	Oxidant	H_2S Separation/ Removal	Sulfur Removal/ Recovery	CO_2 Separa- tion
1	IGCC	1800/1050/1050	2 x Advanced F Class	GEE Radiant Only	95 mol% O_2	Selexol	Claus Plant	
2	IGCC	1800/1000/1000	2 x Advanced F Class	GEE Radiant Only	95 mol% O_2	Selexol	Claus Plant	Selexol 2nd stage
3	IGCC	1800/1050/1050	2 x Advanced F Class	CoP E-Gas™	95 mol% O_2	Refrigerated MDEA	Claus Plant	
4	IGCC	1800/1000/1000	2 x Advanced F Class	CoP E-Gas™	95 mol% O_2	Selexol	Claus Plant	Selexol 2nd stage
5	IGCC	1800/1050/1050	2 x Advanced F Class	Shell	95 mol% O_2	Sulfinol-M	Claus Plant	
6	IGCC	1800/1000/1000	2 x Advanced F Class	Shell	95 mol% O_2	Selexol	Claus Plant	Selexol 2nd stage
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--	--	--	--	--	--	--	--	--
9	PC	2400/1050/1050		Subcritical PC	Air		Wet FGD/ Gypsum	
10	PC	2400/1050/1050		Subcritical PC	Air		Wet FGD/ Gypsum	Amine Absorber
11	PC	3500/1100/1100		Supercritical PC	Air		Wet FGD/ Gypsum	
12	PC	3500/1100/1100		Supercritical PC	Air		Wet FGD/ Gypsum	Amine Absorber
13	NGCC	2400/1050/950	2 x Advanced F Class	HRSG	Air			
14	NGCC	2400/1050/950	2 x Advanced F Class	HRSG	Air			Amine Absorber

All plant configurations are evaluated based on installation at a greenfield site. Since these are state-of-the-art plants, they will have higher efficiencies than the average power plant population. Consequently, these plants would be expected to be near the top of the dispatch list and the study capacity factor is chosen to reflect the maximum availability demonstrated for the specific plant type, i.e. 80 percent for IGCC and 85 percent for PC and NGCC configurations. Since variations in fuel costs and other factors can influence dispatch order and capacity factor, sensitivity of levelized COE to capacity factor is evaluated and presented later in this Executive Summary (Exhibit ES-10) and in the body of the report.

The nominal net plant output for this study is set at 550 MW. The actual net output varies between technologies because the combustion turbines in the IGCC and NGCC cases are manufactured in discrete sizes, but the boilers and steam turbines in the PC cases are readily available in a wide range of capacities. The result is that all of the PC cases have a net output of 550 MW, but the IGCC cases have net outputs ranging from 517 to 640 MW. The range in IGCC net output is caused by the much higher auxiliary load imposed in the CO_2 capture cases, primarily due to CO_2 compression, and the need for extraction steam in the water-gas shift reactions, which reduces steam turbine output. Higher auxiliary load and extraction steam requirements can be accommodated in the PC cases (larger boiler and steam turbine) but not in the IGCC cases where it is impossible to maintain a constant net output from the steam cycle given the fixed input (combustion turbine). Likewise, the two NGCC cases have a net output of 560 and 482 MW because of the combustion turbine constraint.

Exhibit ES-2 shows the cost, performance and environmental profile summary for all cases. The results are discussed below in the following order:

- Performance (efficiency and raw water usage)
- Cost (total plant cost and levelized cost of electricity)
- Environmental profile

PERFORMANCE

ENERGY EFFICIENCY

The net plant efficiency (HHV basis) for all 12 cases is shown in Exhibit ES-3. The primary conclusions that can be drawn are:

- The NGCC with no CO_2 capture has the highest net efficiency of the technologies modeled in this study with an efficiency of 50.8 percent.
- The NGCC case with CO_2 capture results in the highest efficiency (43.7 percent) among all of the capture technologies.
- The NGCC with CO_2 capture results in an efficiency penalty of 7.1 absolute percent, relative to the non-capture case. The NGCC penalty is less than for the PC cases because natural gas is less carbon intensive than coal, and there is less CO_2 to capture and to compress for equal net power outputs.
- The energy efficiency of the IGCC non-capture cases is as follows: the dry-fed Shell gasifier (41.1 percent), the slurry-fed, two-stage CoP gasifier (39.3 percent) and the slurry-fed, single-stage GEE gasifier (38.2 percent).
- When CO_2 capture is added to the IGCC cases, the energy efficiency of all three cases is almost equal, ranging from 31.7 percent for CoP to 32.5 percent for GEE, with Shell intermediate at 32.0 percent.

Exhibit ES-2 Cost and Performance Summary and Environmental Profile for All Cases

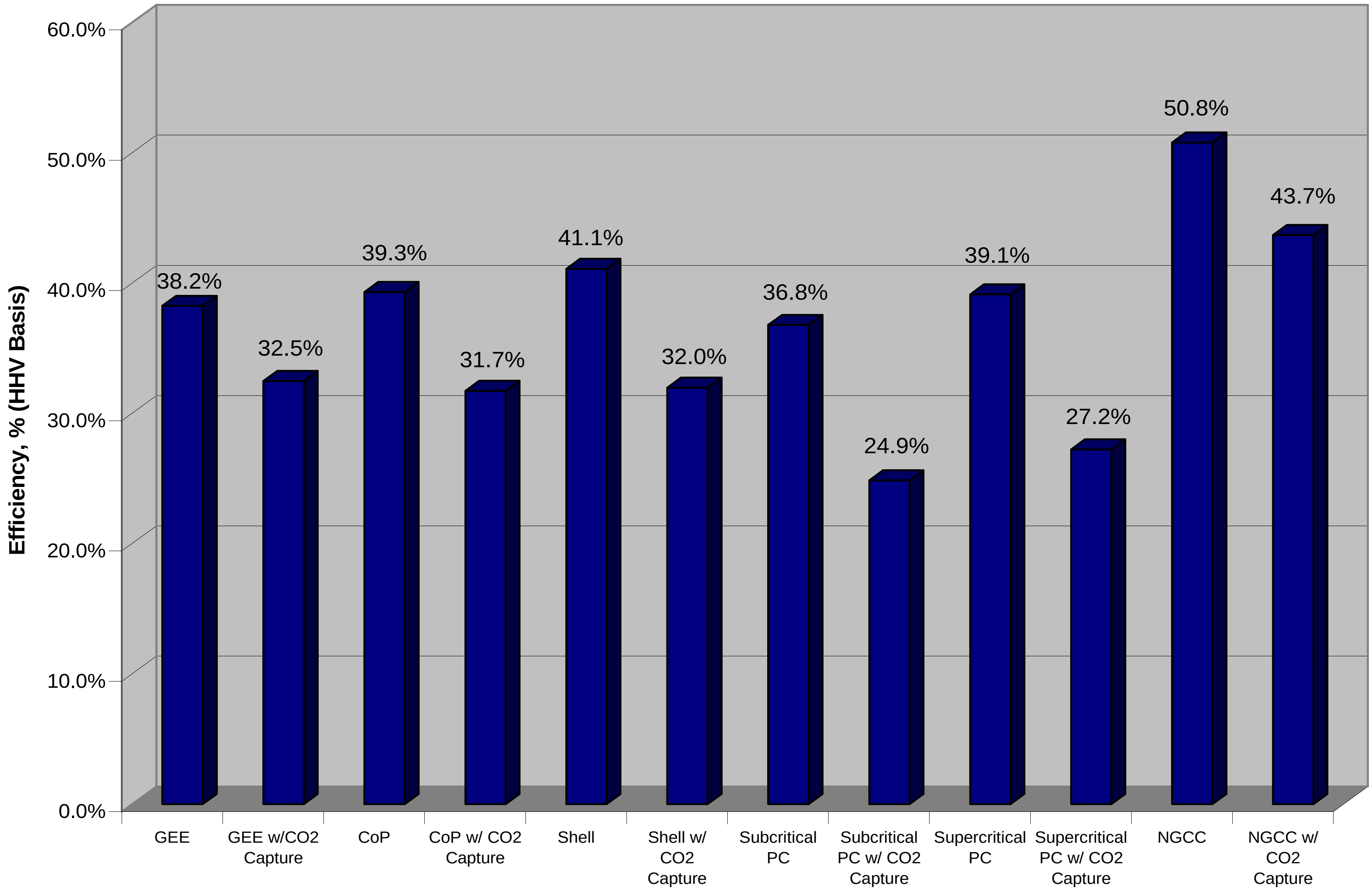
	Integrated Gasification Combined Cycle						Pulverized Coal Boiler				NGCC	
	GEE		CoP		Shell		PC Subcritical		PC Supercritical		Advanced F Class	
	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 9	Case 10	Case 11	Case 12	Case 13	Case 14
CO_2 Capture	No	Yes	No	Yes	No	Yes	No	Yes	No	Yes	No	Yes
Gross Power Output (kW_e)	770,350	744,960	742,510	693,840	748,020	693,555	583,315	679,923	580,260	663,445	570,200	520,090
Auxiliary Power Requirement (kW_e)	130,100	189,285	119,140	175,600	112,170	176,420	32,870	130,310	30,110	117,450	9,840	38,200
Net Power Output (kW_e)	640,250	555,675	623,370	518,240	635,850	517,135	550,445	549,613	550,150	545,995	560,360	481,890
Coal Flowrate (lb/hr)	489,634	500,379	463,889	477,855	452,620	473,176	437,699	646,589	411,282	586,627	N/A	N/A
Natural Gas Flowrate (lb/hr)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	165,182	165,182
HHV Thermal Input (kW_{th})	1,674,044	1,710,780	1,586,023	1,633,771	1,547,493	1,617,772	1,496,479	2,210,668	1,406,161	2,005,660	1,103,363	1,103,363
Net Plant HHV Efficiency (%)	38.2%	32.5%	39.3%	31.7%	41.1%	32.0%	36.8%	24.9%	39.1%	27.2%	50.8%	43.7%
Net Plant HHV Heat Rate (Btu/kW-hr)	8,922	10,505	8,681	10,757	8,304	10,674	9,276	13,724	8,721	12,534	6,719	7,813
Raw Water Usage, gpm	4,003	4,579	3,757	4,135	3,792	4,563	6,212	12,187	5,441	10,444	2,511	3,901
Total Plant Cost ($ x 1,000)	1,160,919	1,328,209	1,080,166	1,259,883	1,256,810	1,379,524	852,612	1,591,277	866,391	1,567,073	310,710	564,628
Total Plant Cost ($/kW)	1,813	2,390	1,733	2,431	1,977	2,668	1,549	2,895	1,575	2,870	554	1,172
LCOE (mills/kWh)[1]	78.0	102.9	75.3	105.7	80.5	110.4	64.0	118.8	63.3	114.8	68.4	97.4
CO_2 Emissions (lb/hr)	1,123,781	114,476	1,078,144	131,328	1,054,221	103,041	1,038,110	152,975	975,370	138,681	446,339	44,634
CO_2 Emissions (tons/year) @ CF[1]	3,937,728	401,124	3,777,815	460,175	3,693,990	361,056	3,864,884	569,524	3,631,301	516,310	1,661,720	166,172
CO_2 Emissions (tonnes/year) @ CF[1]	3,572,267	363,896	3,427,196	417,466	3,351,151	327,546	3,506,185	516,667	3,294,280	468,392	1,507,496	150,750
CO_2 Emissions (lb/MMBtu)	197	19.6	199	23.6	200	18.7	203	20.3	203	20.3	119	11.9
CO_2 Emissions (lb/MWh)[2]	1,459	154	1,452	189	1,409	149	1,780	225	1,681	209	783	85.8
CO_2 Emissions (lb/MWh)[3]	1,755	206	1,730	253	1,658	199	1,886	278	1,773	254	797	93
SO_2 Emissions (lb/hr)	73	56	68	48	55	58	433	Negligible	407	Negligible	Negligible	Negligible
SO_2 Emissions (tons/year) @ CF[1]	254	196	237	167	194	204	1,613	Negligible	1,514	Negligible	Negligible	Negligible
SO_2 Emissions (tonnes/year) @ CF[1]	231	178	215	151	176	185	1,463	Negligible	1,373	Negligible	Negligible	Negligible
SO_2 Emissions (lb/MMBtu)	0.0127	0.0096	0.0125	0.0085	0.0105	0.0105	0.0848	Negligible	0.0847	Negligible	Negligible	Negligible
SO_2 Emissions (lb/MWh)[2]	0.0942	0.0751	0.0909	0.0686	0.0739	0.0837	0.7426	Negligible	0.7007	Negligible	Negligible	Negligible
NOx Emissions (lb/hr)	313	273	321	277	309	269	357	528	336	479	34	34
NOx Emissions (tons/year) @ CF[1]	1,096	955	1,126	972	1,082	944	1,331	1,966	1,250	1,784	127	127
NOx Emissions (tonnes/year) @ CF[1]	994	867	1,021	882	982	856	1,207	1,783	1,134	1,618	115	115
NOx Emissions (lb/MMBtu)	0.055	0.047	0.059	0.050	0.058	0.049	0.070	0.070	0.070	0.070	0.009	0.009
NOx Emissions (lb/MWh)[2]	0.406	0.366	0.433	0.400	0.413	0.388	0.613	0.777	0.579	0.722	0.060	0.066
PM Emissions (lb/hr)	41	41	38	40	37	39	66	98	62	89	Negligible	Negligible
PM Emissions (tons/year) @ CF[1]	142	145	135	139	131	137	247	365	232	331	Negligible	Negligible
PM Emissions (tonnes/year) @ CF[1]	129	132	122	126	119	125	224	331	211	300	Negligible	Negligible
PM Emissions (lb/MMBtu)	0.0071	0.0071	0.0071	0.0071	0.0071	0.0071	0.0130	0.0130	0.0130	0.0130	Negligible	Negligible
PM Emissions (lb/MWh)[2]	0.053	0.056	0.052	0.057	0.050	0.057	0.114	0.144	0.107	0.134	Negligible	Negligible
Hg Emissions (lb/hr)	0.0033	0.0033	0.0031	0.0032	0.0030	0.0032	0.0058	0.0086	0.0055	0.0078	Negligible	Negligible
Hg Emissions (tons/year) @ CF[1]	0.011	0.012	0.011	0.011	0.011	0.011	0.022	0.032	0.020	0.029	Negligible	Negligible
Hg Emissions (tonnes/year) @ CF[1]	0.010	0.011	0.010	0.010	0.010	0.010	0.020	0.029	0.019	0.026	Negligible	Negligible
Hg Emissions (lb/TBtu)	0.571	0.571	0.571	0.571	0.571	0.571	1.14	1.14	1.14	1.14	Negligible	Negligible
Hg Emissions (lb/MWh)[2]	4.24E-06	4.48E-06	4.16E-06	4.59E-06	4.03E-06	4.55E-06	1.00E-05	1.27E-05	9.45E-06	1.18E-05	Negligible	Negligible

[1] Capacity factor is 80% for IGCC cases and 85% for PC and NGCC cases

[2] Value is based on gross output

[3] Value is based on net output

Exhibit ES-3 Net Plant Efficiency (HHV Basis)



- Supercritical PC without CO_2 capture has an efficiency of 39.1 percent, which is nearly equal to the average of the three non-capture IGCC technologies. Subcritical PC has an efficiency of 36.8 percent, which is the lowest of all the non-capture cases in the study.
- The addition of CO_2 capture to the PC cases (Fluor's Econamine FG Plus process) has a much greater impact on efficiency than CO_2 capture in the IGCC cases. This is primarily because the low partial pressure of CO_2 in the flue gas from a PC plant requires a chemical absorption process rather than physical absorption. For chemical absorption processes, the regeneration requirements are much more energy intensive. Thus the energy penalty for both subcritical and supercritical PC is 11.9 absolute percent resulting in post-capture efficiencies of 24.9 percent and 27.2 percent, respectively.

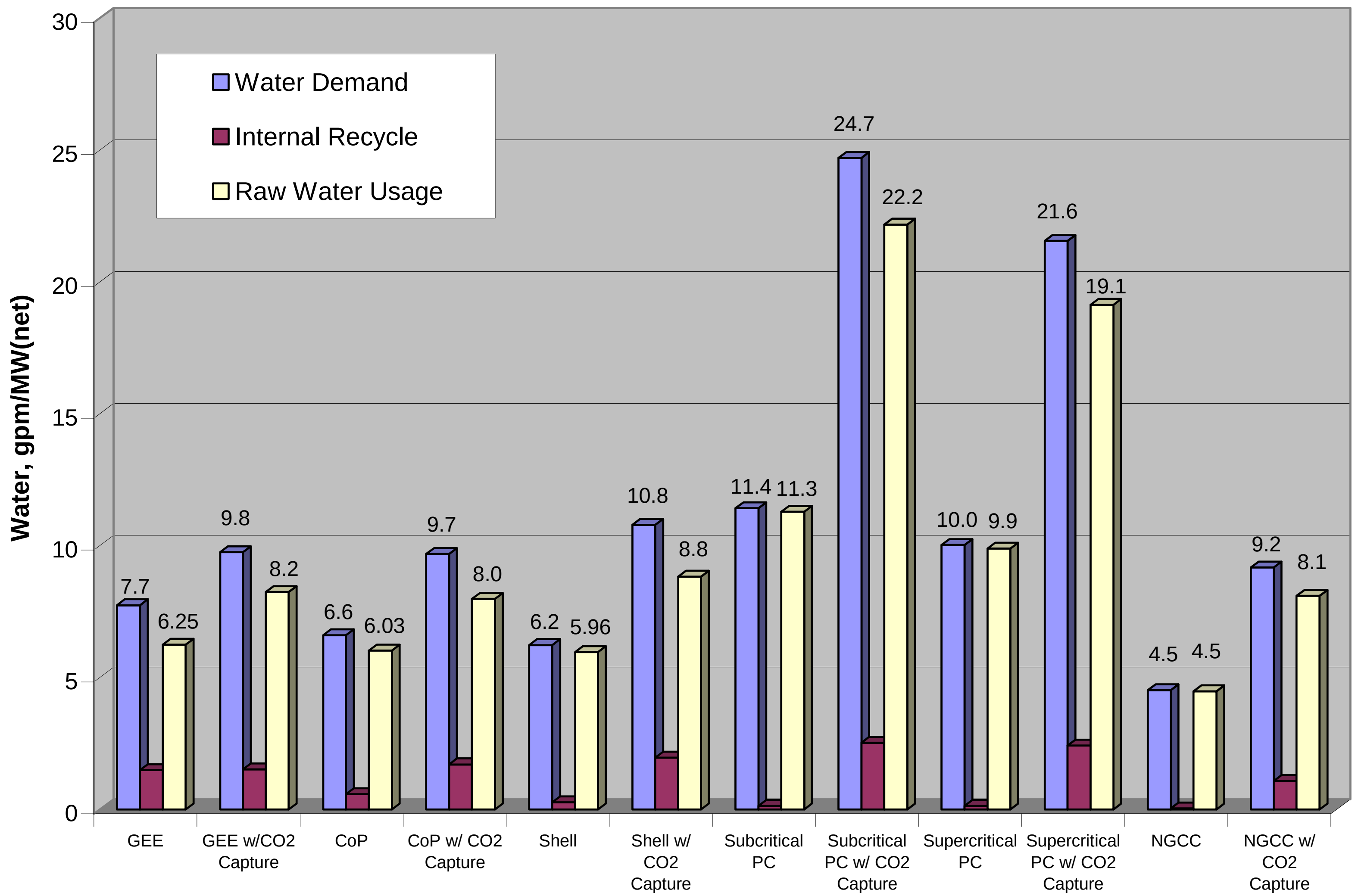
WATER USE

Three water values are presented for each technology in Exhibit ES-4: water demand, internal recycle and raw water usage. Each value is normalized by net output. Demand is the amount of water required to satisfy a particular process (slurry, quench, FGD makeup, etc.) and internal recycle is water available within the process (boiler feedwater blowdown, condensate, etc.). Raw water usage is the difference between demand and recycle, and it represents the overall impact of the process on the water source, which in this study is considered to be 50 percent from groundwater (wells) and 50 percent from a municipal source. All plants are equipped with evaporative cooling towers, and all process blowdown streams are assumed to be treated and recycled to the cooling tower. The primary conclusions that can be drawn are:

- In all cases the primary water consumer is cooling tower makeup, which ranges from 71 to 99 percent of the total raw water usage.
- Among non-capture cases, NGCC requires the least amount of raw water makeup, followed by IGCC and PC. If an average raw water usage for the three IGCC cases and two PC cases is used, the relative normalized raw water usage for the technologies is 2.4:1.4:1.0 (PC:IGCC:NGCC). The relative results are as expected given the much higher steam turbine output in the PC cases which results in higher condenser duties, higher cooling water requirements and ultimately higher cooling water makeup. The IGCC cases and the NGCC case have comparable steam turbine outputs, but IGCC requires additional water for coal slurry (GEE and CoP), syngas quench (GEE), humidification (CoP and Shell), gasifier steam (Shell), and slag handling (all cases), which increases the IGCC water demand over NGCC.
- Among capture cases, the raw water requirement increases (relative to non-capture cases) much more dramatically for the PC and NGCC cases than for IGCC cases because of the large cooling water demand of the Econamine process which results in much greater cooling water makeup requirements. If average water usage values are used for IGCC and PC cases, the relative normalized raw water usage for the technologies in CO_2 capture cases is 2.6:1.03:1.0 (PC:IGCC:NGCC). The NGCC CO_2 capture case still has the lowest water requirement, but the difference between it and the average of the three IGCC cases is minimal.

- CO_2 capture increases the average raw water usage for all three technologies evaluated, but the increase is lowest for the IGCC cases. The average normalized raw water usage for the three IGCC cases increases by about 37 percent due primarily to the need for additional water in the syngas to accomplish the water gas shift reaction and the increased auxiliary load. With the addition of CO_2 capture, PC normalized raw water usage increases by 95 percent and NGCC by 81 percent. The large cooling water demand of the Econamine process drives this substantial increase for PC and NGCC.

Exhibit ES-4 Water Demand and Usage



COST RESULTS

TOTAL PLANT COST

The total plant cost (TPC) for each technology was determined through a combination of vendor quotes, scaled estimates from previous design/build projects, or a combination of the two. TPC includes all equipment (complete with initial chemical and catalyst loadings), materials, labor (direct and indirect), engineering and construction management, and contingencies (process and project). Owner's costs are not included.

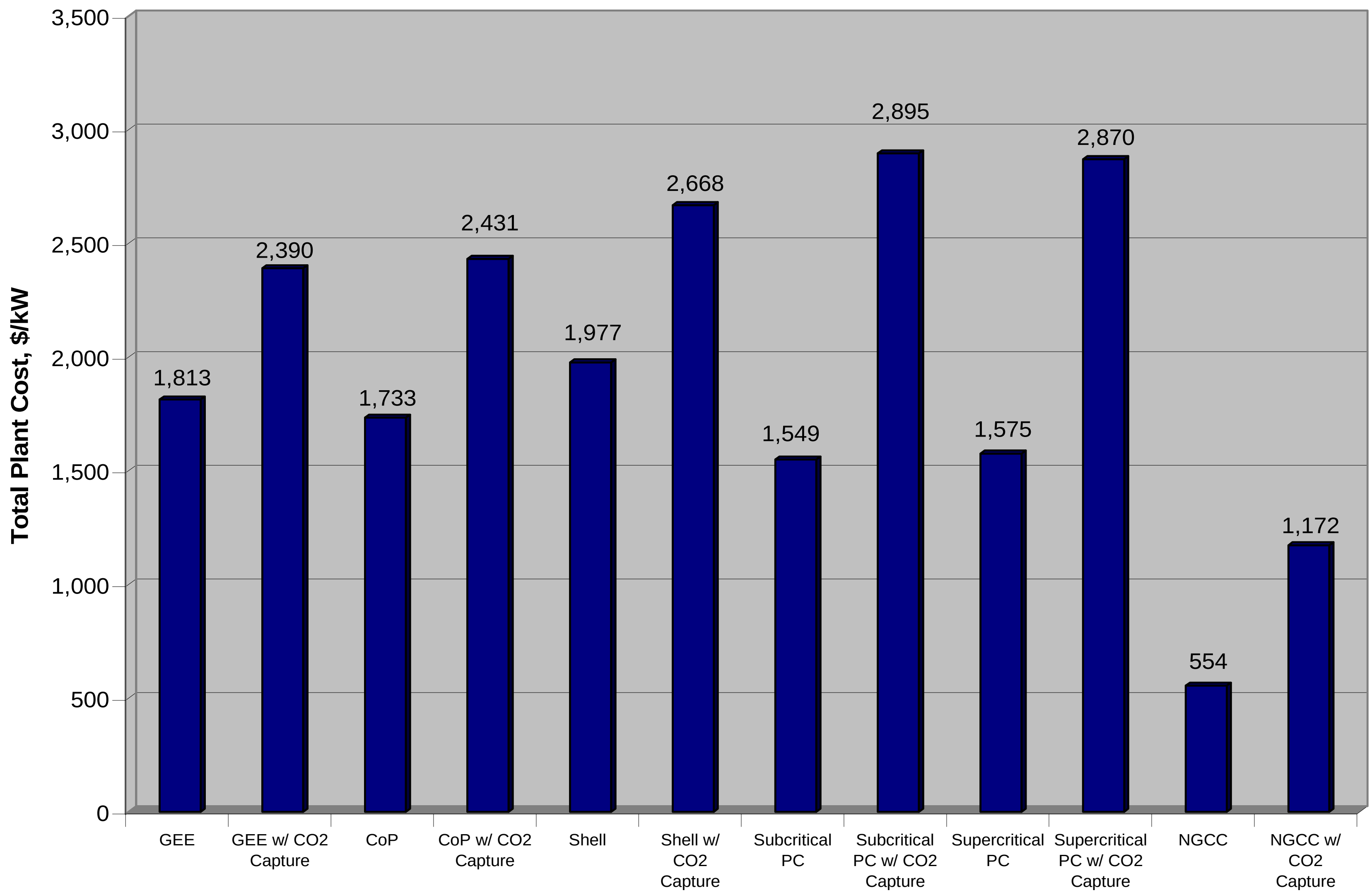
The cost estimates carry an accuracy of ±30 percent, consistent with the screening study level of design engineering applied to the various cases in this study. The value of the study lies not in the absolute accuracy of the individual case results but in the fact that all cases were evaluated under the same set of technical and economic assumptions. This consistency of approach allows meaningful comparisons among the cases evaluated.

Project contingencies were added to the Engineering/Procurement/Construction Management (EPCM) capital accounts to cover project uncertainty and the cost of any additional equipment that would result from a detailed design. The contingencies represent costs that are expected to occur. Each bare erected cost (BEC) account was evaluated against the level of estimate detail and field experience to determine project contingency. Process contingency was added to cost account items that were deemed to be first-of-a-kind or posed significant risk due to lack of operating experience. The cost accounts that received a process contingency include:

- Slurry Prep and Feed – 5 percent on GE IGCC cases - systems are operating at approximately 800 psia as compared to 600 psia for the other IGCC cases.
- Gasifiers and Syngas Coolers – 15 percent on all IGCC cases – next-generation commercial offering and integration with the power island.
- Two Stage Selexol – 20 percent on all IGCC capture cases – lack of operating experience at commercial scale in IGCC service.
- Mercury Removal – 5 percent on all IGCC cases – minimal commercial scale experience in IGCC applications.
- CO_2 Removal System – 20 percent on all PC/NGCC capture cases - post-combustion process unproven at commercial scale for power plant applications.
- Combustion Turbine Generator – 5 percent on all IGCC non-capture cases – syngas firing and ASU integration; 10 percent on all IGCC capture cases – high hydrogen firing.
- Instrumentation and Controls – 5 percent on all IGCC accounts and 5 percent on the PC and NGCC capture cases – integration issues.

The normalized total plant cost (TPC) for each technology is shown in Exhibit ES-5. The following conclusions can be drawn:

Exhibit ES-5 Total Plant Cost



- Among the non-capture cases, NGCC has the lowest capital cost at $554/kW followed by PC with an average cost of $1,562/kW and IGCC with an average cost of $1,841/kW. The average IGCC cost is 18 percent greater than the average PC cost. The process contingency for the IGCC cases ranges from $44-51/kW while there is zero process contingency for the PC and NGCC non-capture cases. The differential between IGCC and PC is reduced to 15 percent when process contingency is eliminated.
- The three IGCC non-capture cases have a capital cost ranging from $1,733/kW (CoP) to $1,977/kW (Shell) with GEE intermediate at $1,813/kW.
- Among the capture cases, NGCC has the lowest capital cost, despite the fact that the capital cost of the NGCC capture case is more than double the cost of the non-capture case at $1,172/kW.
- Among the capture cases, the PC cases have the highest capital cost at an average of $2,883/kW. The average capital cost for IGCC CO_2 capture cases is $2,496/kW, which is 13 percent less than the average of the PC cases. The process contingency for the IGCC capture cases ranges from $101-105/kW, for the PC cases from $99-104/kW and $59/kW for the NGCC case. If process contingency is removed from the PC and IGCC cases, the cost of IGCC is 16 percent less than PC.

LEVELIZED COST OF ELECTRICITY (LCOE)

The 20-year LCOE was calculated for each case using the economic parameters shown in Exhibit ES-6. The cases were divided into two categories, representing high risk and low risk projects undertaken at investor owned utilities. High risk projects are those in which commercial scale operating experience is limited. The IGCC cases (with and without CO_2 capture) and the PC and NGCC cases with CO_2 capture were considered to be high risk. The non-capture PC and NGCC cases were considered to be low risk.

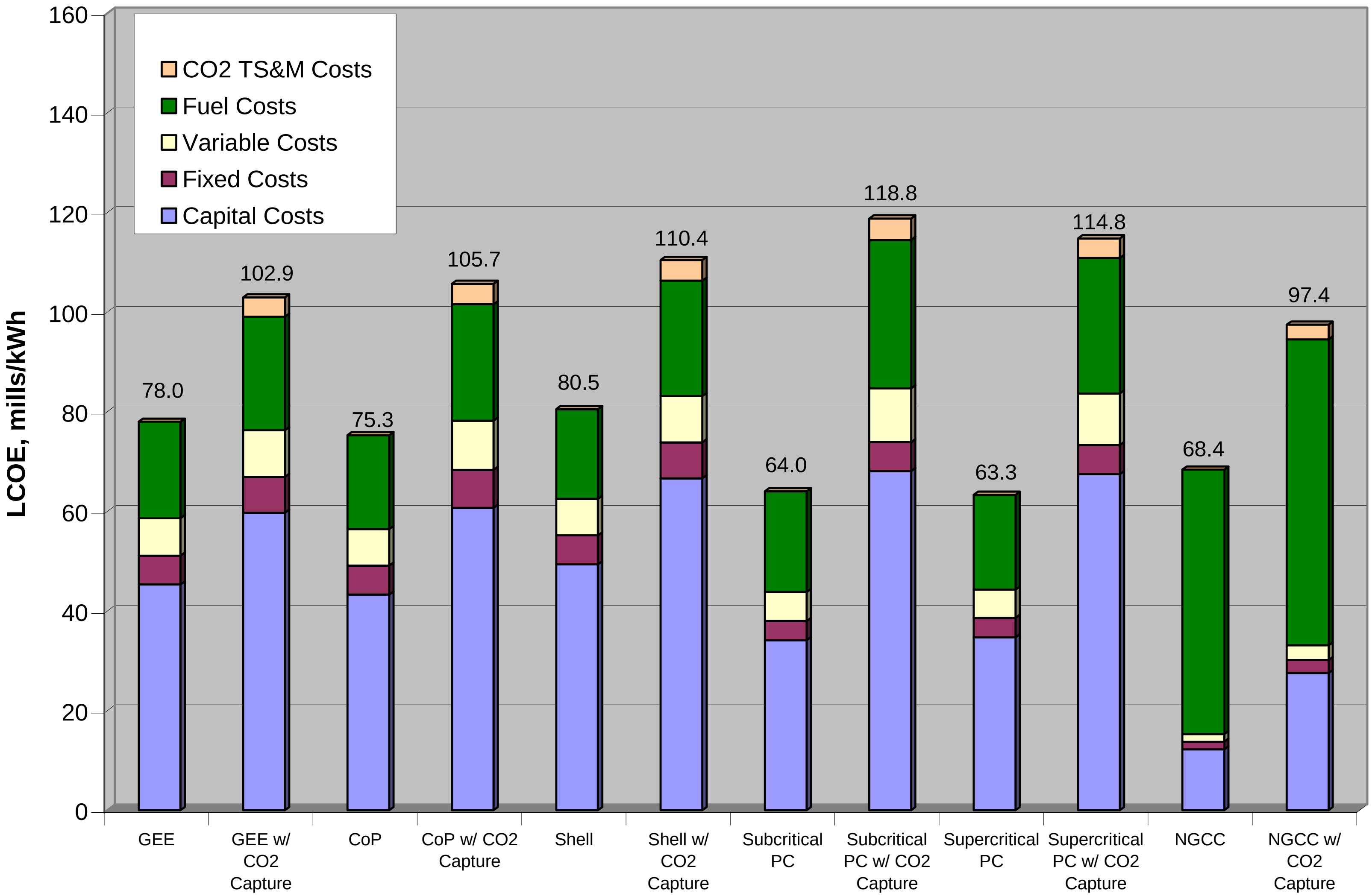
Exhibit ES-6 Economic Parameters Used to Calculate LCOE

	High Risk	Low Risk
Capital Charge Factor	0.175	0.164
Coal Levelization Factor	1.2022	1.2089
Natural Gas Levelization Factor	1.1651	1.1705
Levelization for all other O&M	1.1568	1.1618

The LCOE results are shown in Exhibit ES-7 with the capital cost, fixed operating cost, variable operating cost and fuel cost shown separately. In the capture cases the CO_2 transport, storage and monitoring (TS&M) costs are also shown as a separate bar segment. The following conclusions can be drawn:

- In non-capture cases, PC plants have the lowest LCOE (average 63.7 mills/kWh), followed by NGCC (68.4 mills/kWh) and IGCC (average 77.9 mills/kWh).

Exhibit ES-7 LCOE By Cost Component



- In capture cases, NGCC plants have the lowest LCOE (97.4 mills/kWh), followed by IGCC (average 106.3 mills/kWh) and PC (average 116.8 mills/kWh).
- The LCOE for the three IGCC non-capture cases ranges from 75.3 mills/kWh (CoP) to 80.5 mills/kWh (Shell) with GEE in between at 78.0 mills/kWh. The study level of accuracy is insufficient to distinguish between the LCOE of the three IGCC technologies.
- Non-capture supercritical PC has an LCOE of 63.3 mills/kWh and subcritical PC is 64.0 mills/kWh, an insignificant difference given the level of accuracy of the study estimate.
- PC is the most expensive technology with CO_2 capture, 10 percent higher than IGCC and nearly 20 percent higher than NGCC.
- The capital cost component of LCOE is between 53 and 62 percent in all IGCC and PC cases. It represents only 18 percent of LCOE in the NGCC non-capture case and 28 percent in the CO_2 capture case.
- The fuel component of LCOE ranges from 21-25 percent for the IGCC cases and the PC CO_2 capture cases. For the PC non-capture cases the fuel component varies from 30-32 percent. The fuel component is 78 percent of the total in the NGCC non-capture case and 63 percent in the CO_2 capture case.
- CO_2 transport, storage and monitoring is estimated to add 4 mills/kWh to the LCOE, which is less than 4 perecent of the total LCOE for all capture cases.

Exhibit ES-8 shows the LCOE sensitivity to fuel costs for the non-capture cases. The solid line is the LCOE of NGCC as a function of natural gas cost. The points on the line represent the natural gas cost that would be required to make the LCOE of NGCC equal to PC or IGCC at a given coal cost. The coal prices shown ($1.35, $1.80 and $2.25/MMBtu) represent the baseline cost and a range of ±25 percent around the baseline. As an example, at a coal cost of $1.80/MMBtu, the LCOE of PC equals NGCC at a natural gas price of $6.15/MMBtu.

Another observation from Exhibit ES-8 is that the LCOE of IGCC at a coal price of $1.35/MMBtu is greater than PC at a coal price of $2.25/MMBtu, due to the higher capital cost of IGCC and its relative insensitivity to fuel price. For example, a decrease in coal cost of 40 percent (from $2.25 to $1.35/MMBtu) results in an IGCC LCOE decrease of only 13 percent (82.5 to 73.2 mills/kWh).

Fuel cost sensitivity is presented for the CO_2 capture cases in Exhibit ES-9. Even at the lowest coal cost shown, the LCOE of NGCC is less than IGCC and PC at the baseline natural gas price of $6.75/MMBtu. For the coal-based technologies at the baseline coal cost of $1.80/MMBtu to be equal to NGCC, the cost of natural gas would have to be $7.73/MMBtu (IGCC) or $8.87/MMBtu (PC). Alternatively, for the LCOE of coal-based technologies to be equal to NGCC at the high end coal cost of $2.25/MMBtu, natural gas prices would have to be $8.35/MMBtu for IGCC and $9.65/MMBtu for PC.

Exhibit ES-8 LCOE Sensitivity to Fuel Costs in Non-Capture Cases

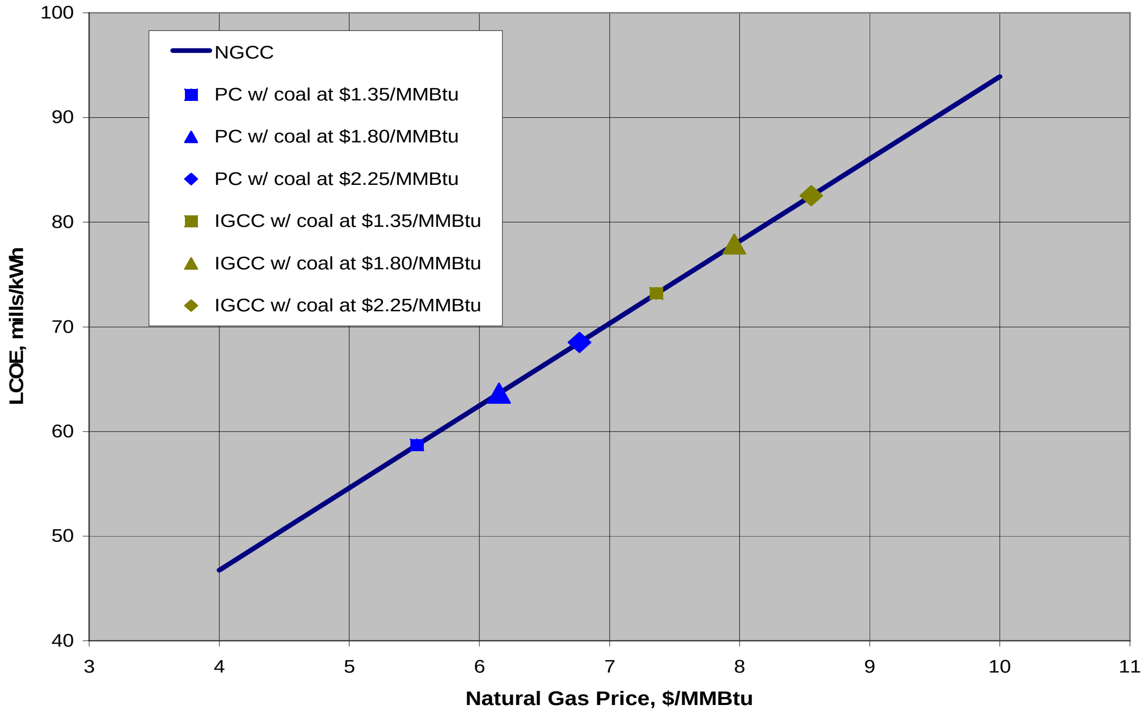
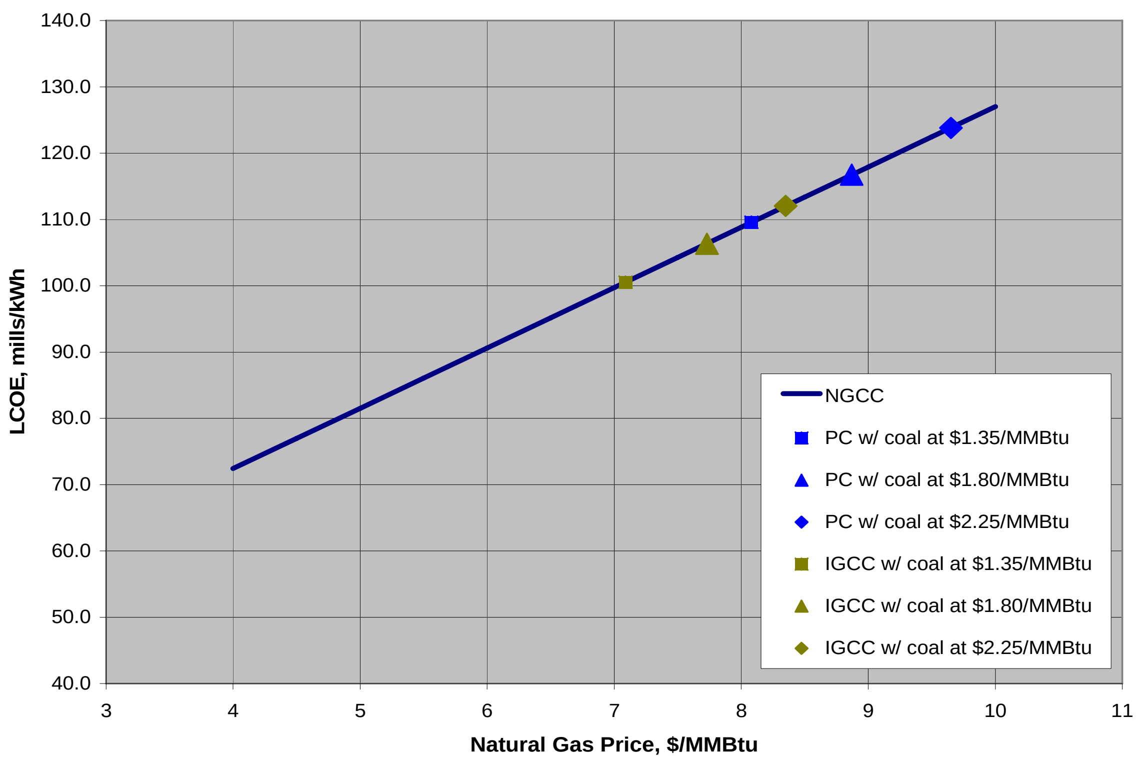
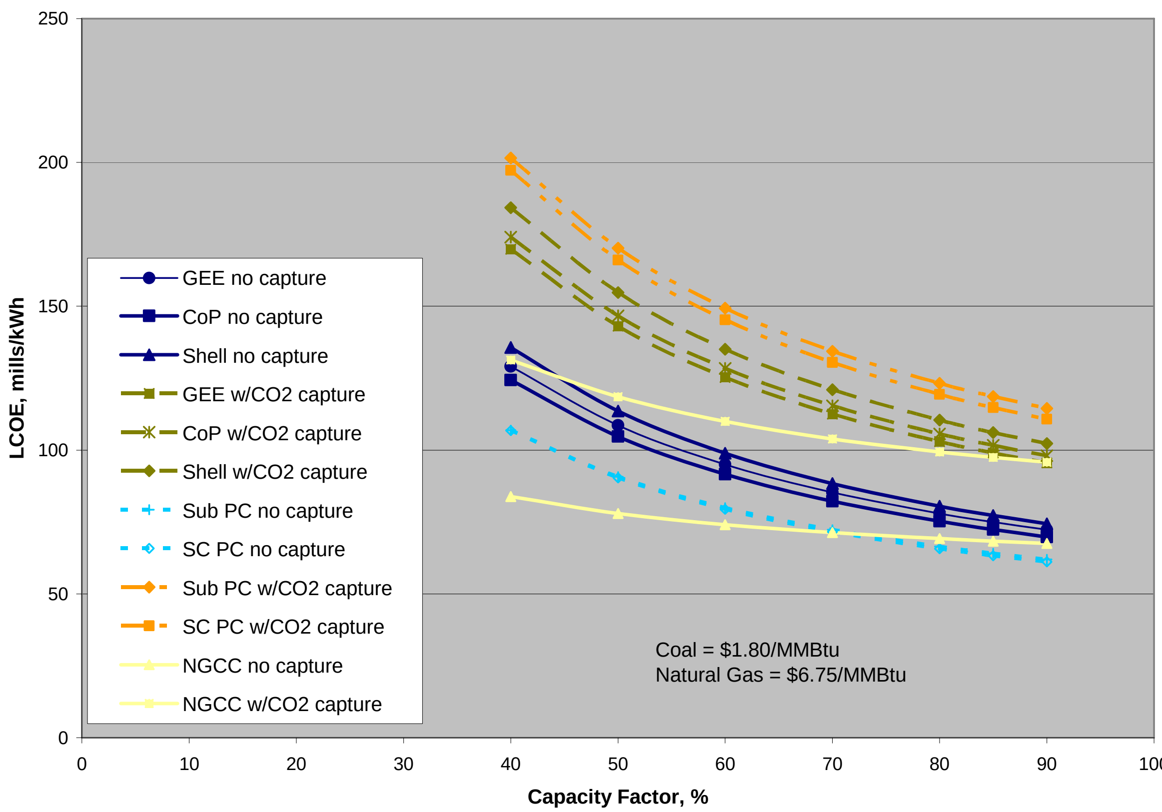


Exhibit ES-9 LCOE Sensitivity to Fuel Costs in CO_2 Capture Cases



The sensitivity of LCOE to capacity factor is shown for all technologies in Exhibit ES-10. The subcritical and supercritical PC cases with no CO_2 capture are nearly identical so that the two curves appear as a single curve on the graph. The capacity factor is plotted from 40 to 90 percent. The baseline capacity factor is 80 percent for IGCC cases with no spare gasifier and is 85 percent for PC and NGCC cases. The curves plotted in Exhibit ES-10 for the IGCC cases assume that the capacity factor could be extended to 90 percent with no spare gasifier. Similarly, the PC and NGCC curves assume that the capacity factor could reach 90 percent with no additional capital equipment.

Exhibit ES-10 LCOE Sensitivity to Capacity Factor



Technologies with high capital cost (PC and IGCC with CO_2 capture) show a greater increase in LCOE with decreased capacity factor. Conversely, NGCC with no CO_2 capture is relatively flat because the LCOE is dominated by fuel charges which decrease as the capacity factor decreases. Conclusions that can be drawn from Exhibit ES-10 include:

- At a capacity factor below 72 percent NGCC has the lowest LCOE in the non-capture cases.
- The LCOE of NGCC with CO_2 capture is the lowest of the capture technologies in the baseline study, and the advantage increases as capacity factor decreases. The relatively low capital cost component of NGCC accounts for the increased cost differential with decreased capacity factor.

- In non-capture cases NGCC at 40 percent capacity factor has the same LCOE as the average of the three IGCC cases at 72 percent capacity factor further illustrating the relatively small impact of capacity factor on NGCC LCOE.

COST OF CO_2 REMOVED/AVOIDED

The cost of CO_2 capture was calculated in two ways, the cost of CO_2 removed and the cost of CO_2 avoided, as illustrated in Equations ES-1 and ES-2, respectively.

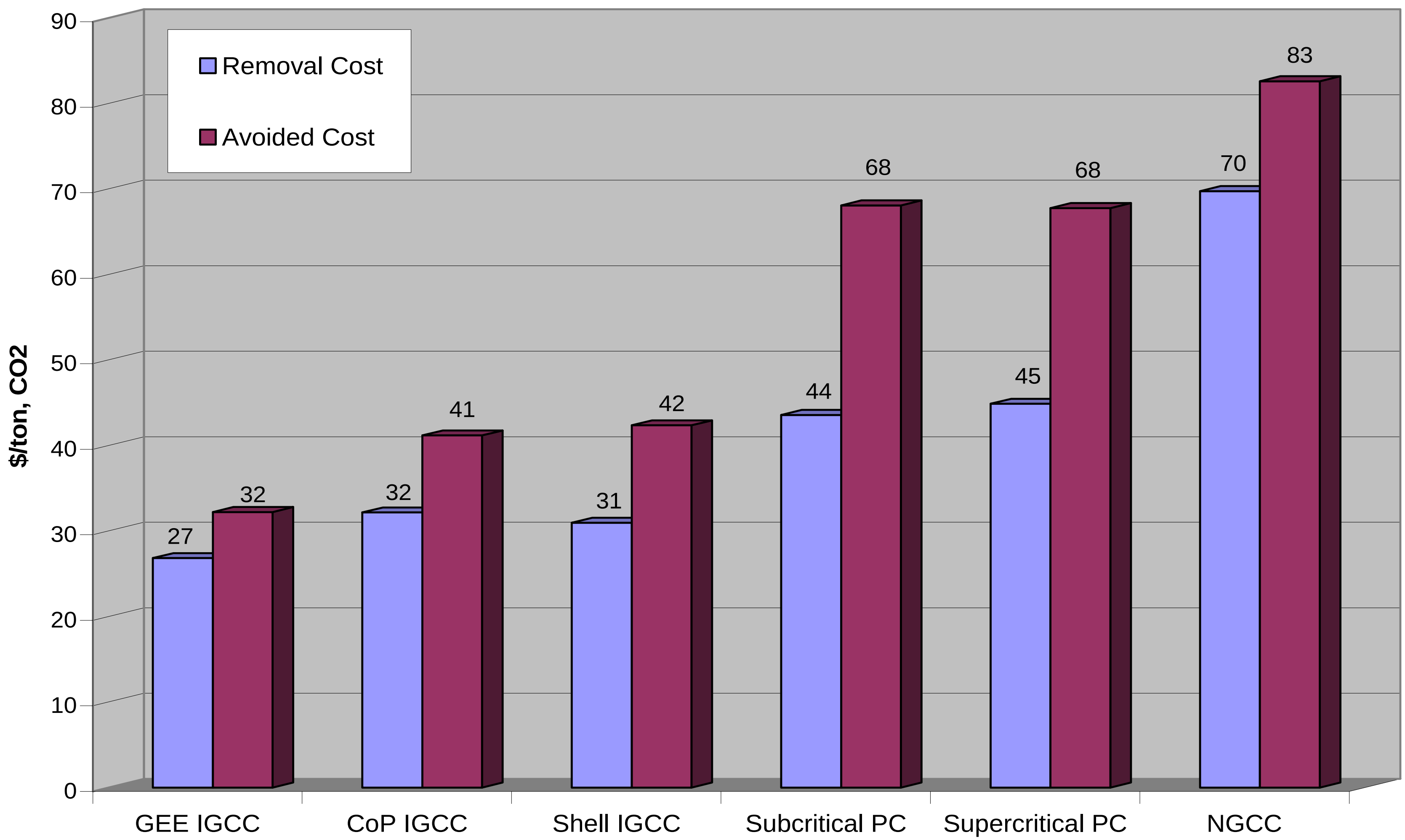
$$Removal\ Cost = \frac{\{LCOE_{with\ removal} - LCOE_{w/o\ removal}\}\ \$/MWh}{\{CO_2\ \ removed\}\ tons/MWh} \qquad \text{(ES-1)}$$

$$Avoided\ Cost = \frac{\{LCOE_{with\ removal} - LCOE_{w/o\ removal}\}\ \$/MWh}{\{Emissions_{w/o\ removal} - Emissions_{with\ removal}\}\ tons/MWh} \qquad \text{(ES-2)}$$

The LCOE with CO_2 removal includes the costs of capture and compression as well as TS&M costs. The resulting removal and avoided costs are shown in Exhibit ES-11 for each of the six technologies modeled. The following conclusions can be drawn:

- The total cost of CO_2 avoided is \$39/ton (average IGCC), \$68/ton (average PC), and \$83/ton (NGCC).
- CO_2 removal and avoided costs for IGCC plants are substantially less than for PC and NGCC because the IGCC CO_2 removal is accomplished prior to combustion and at elevated pressure using physical absorption.
- CO_2 removal and avoided costs for IGCC plants are less than NGCC plants because the baseline CO_2 emissions for NGCC plants are 46 percent less than for IGCC plants. Consequently, the normalized removal cost for NGCC plants is divided by a smaller amount of CO_2.
- CO_2 removal and avoided costs for the GEE IGCC plant are less than for the CoP and Shell IGCC plants. This is consistent with the efficiency changes observed when going from a non-capture to capture configuration for the GEE IGCC plant. The GEE plant started with the lowest efficiency of the IGCC plants but realized the smallest reduction in efficiency between the non-capture and capture configurations.

Exhibit ES-11 CO_2 Capture Costs



ENVIRONMENTAL PERFORMANCE

The environmental targets for each technology are summarized in Exhibit ES-12. Emission rates of SO_2, NOx and PM are shown graphically in Exhibit ES-13, and emission rates of Hg are shown separately in Exhibit ES-14 because of the orders of magnitude difference in emission rate values. Targets were chosen on the basis of the environmental regulations that would most likely apply to plants built in 2010.

Exhibit ES-12 Study Environmental Targets

Technology / Pollutant	IGCC	PC	NGCC
SO_2	0.0128 lb/MMBtu	0.085 lb/MMBtu	Negligible
NOx	15 ppmv (dry) @ 15% O_2	0.070 lb/MMBtu	2.5 ppmv (dry) @ 15% O_2
PM (Filterable)	0.0071 lb/MMBtu	0.013 lb/MMBtu	Negligible
Hg	>90% capture	1.14 lb/TBtu	N/A

Environmental targets were established for each of the technologies as follows:

- IGCC cases use the EPRI targets established in their CoalFleet for Tomorrow work as documented in the *CoalFleet User Design Basis Specification for Coal-Based Integrated Gasification Combined Cycle (IGCC) Power Plants: Version 4*.
- PC and NGCC cases are based on best available control technology.

The primary conclusions that can be drawn are:

- The NGCC baseline plant generates the lowest emissions, followed by IGCC and then PC.
- In NGCC cases, study assumptions result in zero emissions of SO_2, PM and Hg. If the pipeline natural gas contained the maximum amount of sulfur allowed by EPA definition (0.6 gr/100 scf), SO_2 emissions would be 0.000839 kg/GJ (0.00195 lb/MMBtu).
- Based on vendor data it was assumed that dry low NOx burners could achieve 25 ppmv (dry) at 15 percent O_2 and, coupled with a selective catalytic reduction (SCR) unit that achieves 90 percent NOx reduction efficiency, would result in the environmental target of 2.5 ppmv (dry) at 15 percent O_2 for both NGCC cases.
- Based on vendor data it was assumed that Selexol, Sulfinol-M and refrigerated MDEA could all meet the sulfur environmental target, hence emissions of approximately 0.0128 lb/MMBtu in each of the IGCC non-capture cases. In the CO_2 capture cases, to achieve 95 percent CO_2 capture from the syngas, the sulfur removal is greater than in the non-capture cases resulting in emissions of approximately 0.0041 kg/GJ (0.0095 lb/MMBtu).

Exhibit ES-13 SO_2, NOx and Particulate Emission Rates

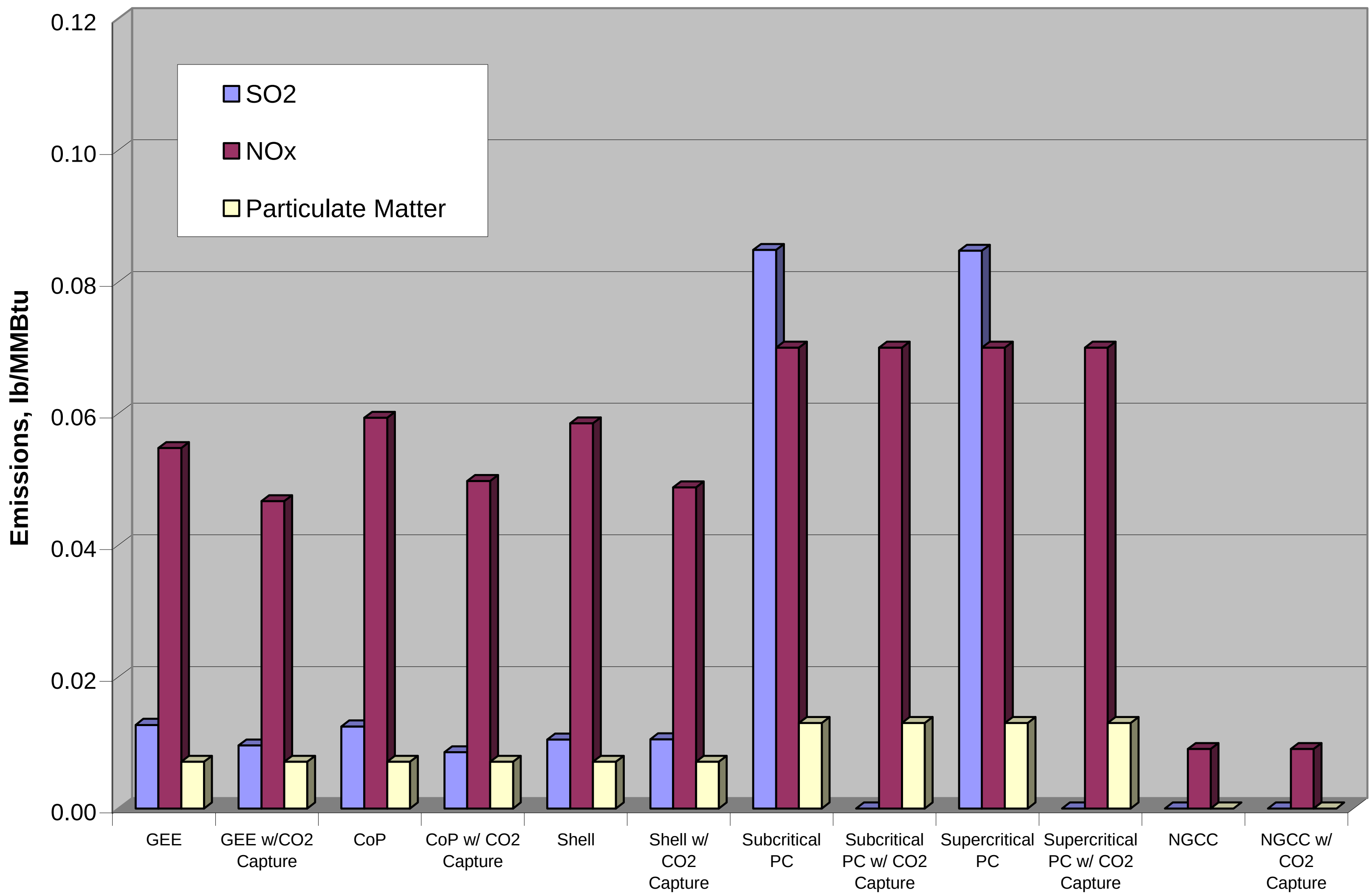
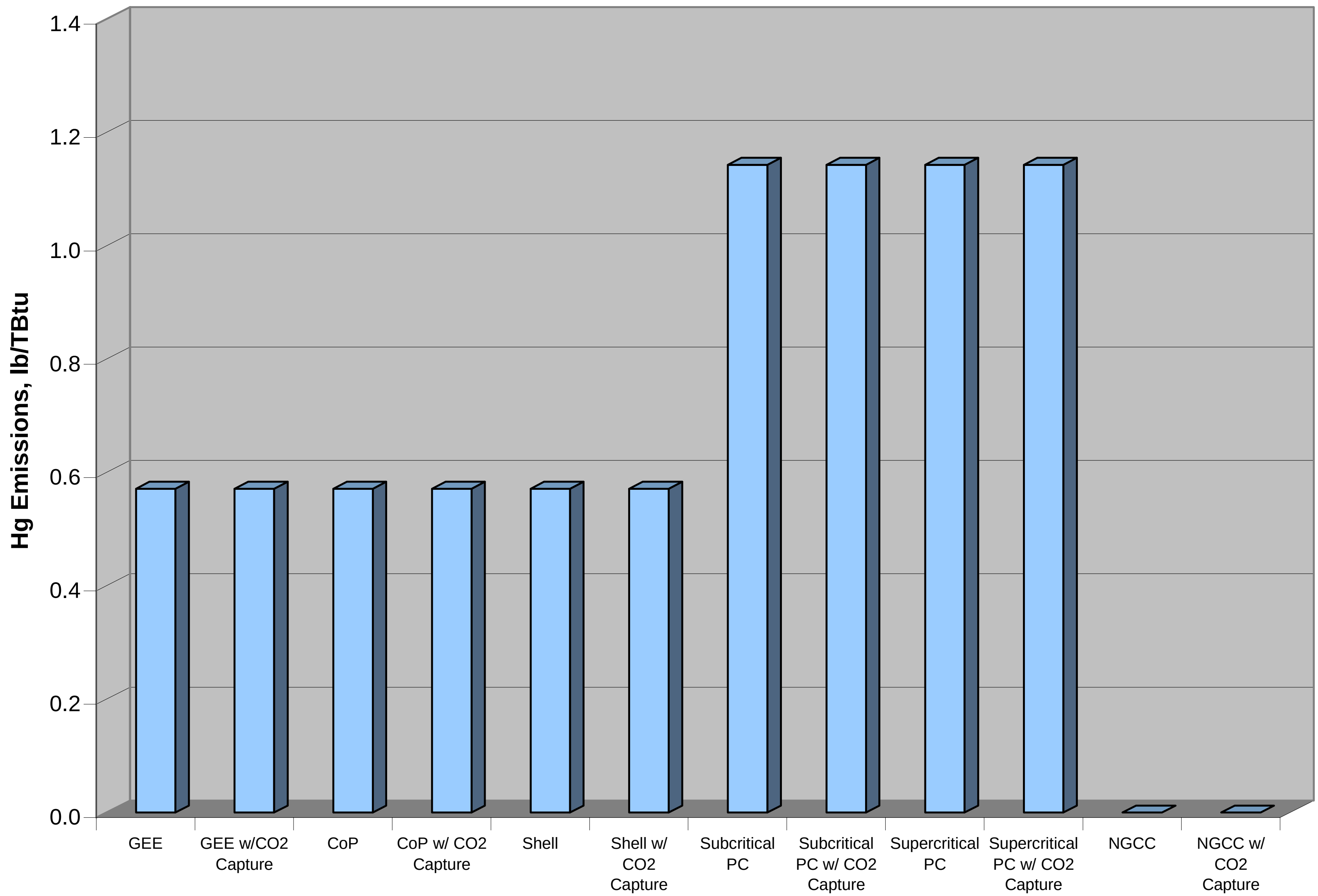


Exhibit ES-14 Mercury Emission Rates



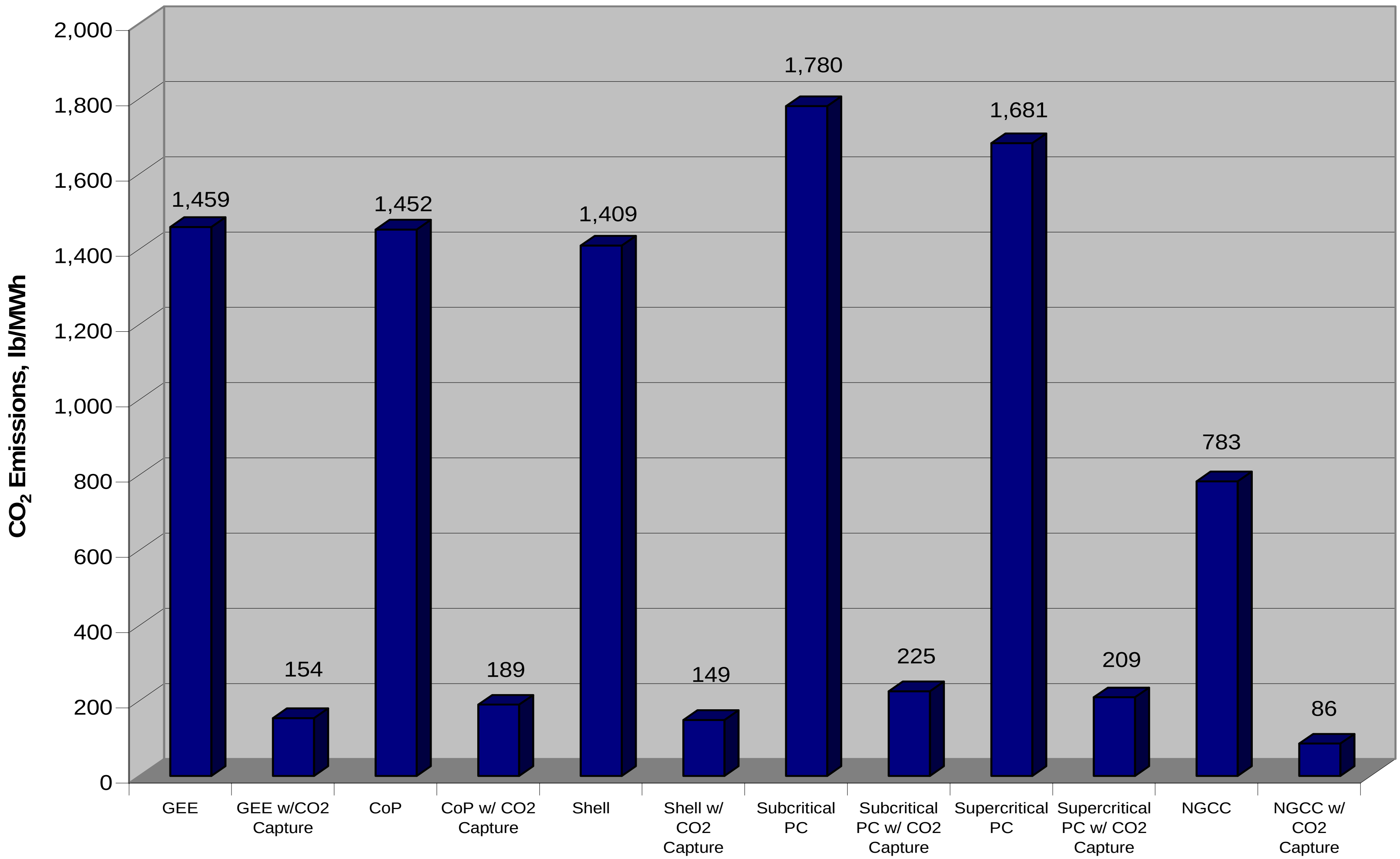
- It was a study assumption that each IGCC technology could meet the filterable particulate emission limit with the combination of technologies employed. In the case of Shell and CoP, this consists of cyclones, candle filters and the syngas scrubber. In the case of GEE particulate control consists of a water quench and syngas scrubber.
- Based on vendor data it was assumed that a combination of low NOx burners and nitrogen dilution could limit IGCC NOx emissions to the environmental target of 15 ppmv (dry) at 15 percent O_2. The small variations in NOx emissions are due to small variations in combustion turbine gas volumes.
- Based on vendor data it was assumed that 95 percent Hg removal could be achieved using carbon beds thus meeting the environmental target. The Hg emissions are reported in Exhibit ES-14 as lb/10 per trillion Btu to make the values the same order of magnitude as the other reported values.
- It was a study assumption that the PC flue gas desulfurization (FGD) unit would remove 98 percent of the inlet SO_2, resulting in the environmental target of 0.037 kg/GJ (0.085 lb/MMBtu). In the CO_2 capture cases, the Econamine system employs a polishing scrubber to reduce emissions to 10 ppmv entering the CO_2 absorber. Nearly all of the remaining SO_2 is absorbed by the Econamine solvent resulting in negligible emissions of SO_2 in those cases.
- In PC cases, it was a study assumption that a fabric filter would remove 99.9 percent of the entering particulate and that there is an 80/20 split between fly ash and bottom ash. The result is the environmental target of 0.006 kg/GJ (0.013 lb/MMBtu) of filterable particulate.
- In PC cases, it was a study assumption that NOx emissions exiting the boiler equipped with low NOx burners and overfire air would be 0.22 kg/GJ (0.50 lb/MMBtu) and that an SCR unit would further reduce the NOx by 86 percent, resulting in the environmental target of 0.030 kg/GJ (0.070 lb/MMBtu).
- In PC cases, it was a study assumption that the environmental target of 90 percent of the incoming Hg would be removed by the combination of SCR, fabric filter and wet FGD thus eliminating the need for activated carbon injection. The resulting Hg emissions for each of the PC cases are 4.92×10^{-7} kg/GJ (1.14 lb/TBtu).

Carbon dioxide emissions are not currently regulated. However, since there is increasing momentum for establishing carbon limits, it was an objective of this study to examine the relative amounts of carbon capture achievable among the six technologies. CO_2 emissions are presented in Exhibit ES-15 for each case, normalized by gross output. In the body of the report CO_2 emissions are presented on both a net and gross MWh basis. New Source Performance Standards (NSPS) contain emission limits for SO_2 and NOx on a lb/(gross) MWh basis. However, since CO_2 emissions are not currently regulated, the potential future emission limit basis is not known and hence the two reported values of CO_2. The following conclusions can be drawn:

- In cases with no carbon capture, NGCC emits 55 percent less CO_2 than PC and 46 percent less CO_2 than IGCC per unit of gross output. The lower NGCC CO_2 emissions reflect the lower carbon intensity of natural gas relative to coal. Based on the fuel compositions used in this study, natural gas contains 32 pounds of carbon per million Btu of heat input and coal contains 55 pounds per million Btu.

- The CO_2 reduction goal in this study was a nominal 90 percent in all cases. The result is that the controlled CO_2 emissions follow the same trend as the uncontrolled, i.e., the NGCC case emits less CO_2 than the IGCC cases which emit less than the PC cases.
- In the IGCC cases the nominal 90 percent CO_2 reduction was accomplished by adding sour gas shift (SGS) reactors to convert CO to CO_2 and using a two-stage Selexol process with a second stage CO_2 removal efficiency of up to 95 percent, a number that was supported by vendor quotes. In the GEE CO_2 capture case, two stages of SGS and a Selexol CO_2 removal efficiency of 92 percent were required, which resulted in 90.2 percent reduction of CO_2 in the syngas. The CoP capture case required three stages of SGS and 95 percent CO_2 capture in the Selexol process, which resulted in 88.4 percent reduction of CO_2 in the syngas. In the CoP case, the capture target of 90 percent could not be achieved because of the high syngas methane content (3.5 vol% compared to 0.10 vol% in the GEE gasifier and 0.04 vol% in the Shell gasifier). The Shell capture case required two stages of SGS and 95 percent capture in the Selexol process, which resulted in 90.8 percent reduction of CO_2 in the syngas.
- The CO_2 emissions in the three non-capture IGCC cases are nearly identical. The slight difference reflects the relative efficiency between the three technologies. The emissions in the CO_2 capture cases are nearly identical for the Shell and GEE cases, but about 19 percent higher in the CoP case because of the high syngas CH_4 content discussed above.
- The PC and NGCC cases both assume that all of the carbon in the fuel is converted to CO_2 in the flue gas and that 90 percent is subsequently removed in the Econamine FG Plus process, which was also supported by a vendor quote.

Exhibit ES-15 CO_2 Emissions Normalized By Gross Output



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1 INTRODUCTION

The objective of this report is to present an accurate, independent assessment of the cost and performance of fossil energy power systems, specifically integrated gasification combined cycle (IGCC), pulverized coal (PC), and natural gas combined cycle (NGCC) plants, in a consistent technical and economic manner that accurately reflects current market conditions for plants starting operation in 2010. This is Volume 1 of a three volume report. The three volume series consists of the following:

- Volume 1: Electricity production only using bituminous coal for coal-based technologies
- Volume 2: Synthetic natural gas production and repowering using a variety of coal types
- Volume 3: Electricity production only from low rank coal (PC and IGCC)

The cost and performance of the various fossil fuel-based technologies will largely determine which technologies will be utilized to meet the demands of the power market. Selection of new generation technologies will depend on many factors, including:

- Capital and operating costs
- Overall energy efficiency
- Fuel prices
- Cost of electricity (COE)
- Availability, reliability and environmental performance
- Current and potential regulation of air, water, and solid waste discharges from fossil-fueled power plants
- Market penetration of clean coal technologies that have matured and improved as a result of recent commercial-scale demonstrations under the Department of Energy's (DOE) Clean Coal Programs

Twelve different power plant design configurations were analyzed. The configurations are listed in Exhibit 1-1. The list includes six IGCC cases utilizing the General Electric Energy (GEE), ConocoPhillips (CoP), and Shell gasifiers each with and without CO_2 capture, and six cases representing conventional technologies: PC-subcritical, PC-supercritical, and NGCC plants both with and without CO_2 capture. While input was sought from various technology vendors, the final assessment of performance and cost was determined independently, and may not represent the views of the technology vendors. The extent of collaboration with technology vendors varied from case to case, with minimal or no collaboration obtained from some vendors.

Cases 7 and 8 were originally included in this study and involve production of synthetic natural gas (SNG) and the repowering of an existing NGCC facility using SNG. The two SNG cases were subsequently moved to Volume 2 of this report resulting in the discontinuity of case numbers (1-6 and 9-14). The two SNG cases are now cases 2 and 2a in Volume 2.

GENERATING UNIT CONFIGURATIONS

A summary of plant configurations considered in this study is presented in Exhibit 1-1. Components for each plant configuration are described in more detail in the corresponding report sections for each case.

The IGCC cases have different gross and net power outputs because of the gas turbine size constraint. The advanced F-class turbine used to model the IGCC cases comes in a standard size of 232 MW when operated on syngas. Each case uses two combustion turbines for a combined gross output of 464 MW. In the combined cycle a heat recovery steam generator extracts heat from the combustion turbine exhaust to power a steam turbine. However, the carbon capture cases consume more extraction steam than the non-capture cases, thus reducing the steam turbine output. In addition, the capture cases have a higher auxiliary load requirement than non-capture cases, which serves to further reduce net plant output. While the two combustion turbines provide 464 MW gross output in all six cases, the overall combined cycle gross output ranges from 694 to 770 MW, which results in a range of net output from 517 to 640 MW. The coal feed rate required to achieve the gross power output is also different between the six cases, ranging from 204,117 to 226,796 kg/h (450,000 to 500,000 lb/h).

Similar to the IGCC cases, the NGCC cases do not have a common net power output. The NGCC system is again constrained by the available combustion turbine size, which is 185 MW for both cases (based on the same advanced F class turbine used in the IGCC cases). Since the carbon capture case requires both a higher auxiliary power load and a significant amount of extraction steam, which significantly reduces the steam turbine output, the net output in the NGCC case is also reduced.

All four PC cases have a net output of 550 MW. The boiler and steam turbine industry’s ability to match unit size to a custom specification has been commercially demonstrated enabling a common net output comparison of the PC cases in this study. The coal feed rate was increased in the carbon capture cases to increase the gross steam turbine output and account for the higher auxiliary load, resulting in a constant net output.

The balance of this report is organized as follows:

- Chapter 2 provides the basis for technical, environmental and cost evaluations.
- Chapter 3 describes the IGCC technologies modeled and presents the results for the six IGCC cases.
- Chapter 4 describes the PC technologies modeled and presents the results for the four PC cases.
- Chapter 5 desribes the NGCC technologies modeled and presents the results for the two NGCC cases.
- Chapter 6 contains the reference list.

Exhibit 1-1 Case Descriptions

Case	Unit Cycle	Steam Cycle, psig/°F/°F	Combustion Turbine	Gasifier/Boiler Technology	Oxidant	H_2S Separation/ Removal	Sulfur Removal/ Recovery	PM Control	NOx Control	CO_2 Separa-tion	CO_2 Capture	CO_2 Sequestra-tion
1	IGCC	1800/1050/1050	2 x Advanced F Class	GEE Radiant Only	95 mol% O_2	Selexol	Claus Plant	Quench, scrubber and AGR adsorber	N_2 dilution			
2	IGCC	1800/1000/1000	2 x Advanced F Class	GEE Radiant Only	95 mol% O_2	Selexol	Claus Plant	Quench, scrubber and AGR adsorber	N_2 dilution	Selexol 2nd stage	90% (1)	Off-Site
3	IGCC	1800/1050/1050	2 x Advanced F Class	CoP E-Gas™	95 mol% O_2	Refrigerated MDEA	Claus Plant	Cyclone, barrier filter and scrubber	N_2 dilution			
4	IGCC	1800/1000/1000	2 x Advanced F Class	CoP E-Gas™	95 mol% O_2	Selexol	Claus Plant	Cyclone, barrier filter and scrubber	N_2 dilution	Selexol 2nd stage	88% (1)	Off-Site
5	IGCC	1800/1050/1050	2 x Advanced F Class	Shell	95 mol% O_2	Sulfinol-M	Claus Plant	Cyclone, barrier filter and scrubber	N_2 dilution			
6	IGCC	1800/1000/1000	2 x Advanced F Class	Shell	95 mol% O_2	Selexol	Claus Plant	Cyclone, barrier filter and scrubber	N_2 dilution	Selexol 2nd stage	90% (1)	Off-Site
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9	PC	2400/1050/1050		Subcritical PC	Air		Wet FGD/ Gypsum	Baghouse	LNB w/OFA and SCR			
10	PC	2400/1050/1050		Subcritical PC	Air		Wet FGD/ Gypsum	Baghouse	LNB w/OFA and SCR	Amine Absorber	90%	Off-Site
11	PC	3500/1100/1100		Supercritical PC	Air		Wet FGD/ Gypsum	Baghouse	LNB w/OFA and SCR			
12	PC	3500/1100/1100		Supercritical PC	Air		Wet FGD/ Gypsum	Baghouse	LNB w/OFA and SCR	Amine Absorber	90%	Off-Site
13	NGCC	2400/1050/950	2 x Advanced F Class	HRSG	Air				LNB and SCR			
14	NGCC	2400/1050/950	2 x Advanced F Class	HRSG	Air				LNB and SCR	Amine Absorber	90%	Off-Site

Note (1) Defined as the percentage of carbon in the syngas that is captured; differences are explained in Chapter 3.

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2 GENERAL EVALUATION BASIS

For each of the plant configurations in this study an AspenPlus model was developed and used to generate material and energy balances, which in turn were used to provide a design basis for items in the major equipment list. The equipment list and material balances were used as the basis for generating the capital and operating cost estimates. Performance and process limits were based upon published reports, information obtained from vendors and users of the technology, performance data from design/build utility projects, and/or best engineering judgement. Capital and operating costs were estimated by WorleyParsons based on simulation results and through a combination of vendor quotes, scaled estimates from previous design/buil projects, or a combination of the two. Ultimately a 20-year levelized cost of electricity (LCOE) was calculated for each of the cases and is reported as the revenue requirement figure-of-merit.

The balance of this chapter documents the design basis common to all technologies, as well as environmental targets and cost assumptions used in the study. Technology specific design criteria are covered in subsequent chapters.

2.1 SITE CHARACTERISTICS

All plants in this study are assumed to be located at a generic plant site in Midwestern USA, with ambient conditions and site characteristics as presented in Exhibit 2-1 and Exhibit 2-2. The ambient conditions are the same as ISO conditions.

Exhibit 2-1 Site Ambient Conditions

Elevation, m (ft)	0
Barometric Pressure, MPa (psia)	0.10 (14.696)
Design Ambient Temperature, Dry Bulb, °C (°F)	15 (59)
Design Ambient Temperature, Wet Bulb, °C (°F)	11 (51.5)
Design Ambient Relative Humidity, %	60

Exhibit 2-2 Site Characteristics

Location	Greenfield, Midwestern USA
Topography	Level
Size, acres	300 (PC/IGCC) 100 (NGCC)
Transportation	Rail
Ash/Slag Disposal	Off Site
Water	Municipal (50%) / Groundwater (50%)
Access	Land locked, having access by train and highway
CO_2 Storage	Compressed to 15.3 MPa (2,215 psia), transported 80 kilometers (50 miles) and sequestered in a saline formation at a depth of 1,239 meters (4,055 feet)

The land area for PC and IGCC cases assumes 30 acres are required for the plant proper and the balance provides a buffer of approximately 0.25 miles to the fence line. The extra land could also provide for a rail loop if required. In the NGCC cases it was assumed the plant proper occupies about 10 acres leaving a buffer of 0.15 miles to the plant fence line.

In all cases it was assumed that the steam turbine is enclosed in a turbine building and in the PC cases the boiler is also enclosed. The gasifier in the IGCC cases and the combustion turbines in the IGCC and NGCC cases are not enclosed.

The following design parameters are considered site-specific, and are not quantified for this study. Allowances for normal conditions and construction are included in the cost estimates.

- Flood plain considerations
- Existing soil/site conditions
- Water discharges and reuse
- Rainfall/snowfall criteria
- Seismic design
- Buildings/enclosures
- Fire protection
- Local code height requirements
- Noise regulations – Impact on site and surrounding area

2.2 COAL CHARACTERISTICS

The design coal is Illinois No. 6 with characteristics presented in Exhibit 2-3. The coal properties are from NETL's Coal Quality Guidelines. [1]

The first year cost of coal used in this study is $1.71/MMkJ ($1.80/MMBtu) (2010 cost of coal in 2007 dollars). The cost was determined using the following information from the Energy Information Administration's (EIA) 2007 Annual Energy Outlook (AEO):

- The 2010 minemouth cost of coal in 2005 dollars, $35.23/tonne ($31.96/ton), was obtained from Supplemental Table 113 of the EIA's 2007 AEO for eastern interior high-sulfur bituminous coal.
- The delivery costs were assumed to be 25 percent of the minemouth cost for eastern interior coal delivered to Illinois and surrounding states. [2]
- The 2010 delivered cost ($44.04/tonne [$39.95/ton]) was escalated to 2007 dollars using the gross domestic product (GDP) chain-type price index from AEO 2007, resulting in a delivered 2010 price in 2007 dollars of $45.32/tonne ($41.11/ton) or $1.71/MMkJ ($1.80/MMBtu). [3] (Note: The conversion of $41.11/ton to dollars per million Btu results in $1.8049/MMBtu which was used in calculations, but only two decimal places are shown in the report.)

Exhibit 2-3 Design Coal

Rank	**Bituminous**	
Seam	**Illinois No. 6 (Herrin)**	
Source	**Old Ben Mine**	
Proximate Analysis (weight %) (Note A)		
	As Received	**Dry**
Moisture	11.12	0.00
Ash	9.70	10.91
Volatile Matter	34.99	39.37
Fixed Carbon	44.19	49.72
Total	100.00	100.00
Sulfur	2.51	2.82
HHV, kJ/kg	27,113	30,506
HHV, Btu/lb	11,666	13,126
LHV, kJ/kg	26,151	29,544
LHV, Btu/lb	11,252	12,712
Ultimate Analysis (weight %)		
	As Received	**Dry**
Moisture	11.12	0.00
Carbon	63.75	71.72
Hydrogen	4.50	5.06
Nitrogen	1.25	1.41
Chlorine	0.29	0.33
Sulfur	2.51	2.82
Ash	9.70	10.91
Oxygen (Note B)	6.88	7.75
Total	100.00	100.00

Notes: A. The proximate analysis assumes sulfur as volatile matter
B. By difference

2.3 NATURAL GAS CHARACTERISTICS

Natural gas is utilized as the main fuel in Cases 13 and 14 (NGCC with and without CO_2 capture), and its composition is presented in Exhibit 2-4. [4]

Exhibit 2-4 Natural Gas Composition

Component		Volume Percentage
Methane	CH_4	93.9
Ethane	C_2H_6	3.2
Propane	C_3H_8	0.7
n-Butane	C_4H_{10}	0.4
Carbon Dioxide	CO_2	1.0
Nitrogen	N_2	0.8
	Total	100.0

	LHV	HHV
kJ/kg	47,764	52,970
MJ/scm	35	39
Btu/lb	20,552	22,792
Btu/scf	939	1,040

Note: Fuel composition is normalized and heating values are calculated

The first year cost of natural gas used in this study is $6.40/MMkJ ($6.75/MMBtu) (2010 cost of natural gas in 2007 dollars). The cost was determined using the following information from the EIA's 2007 AEO:

- The 2010 national average delivered cost of natural gas to electric utilities in 2005 dollars, $6.07/MMkJ ($6.40/MMBtu), was obtained from the AEO 2007 reference case Table 13.
- The 2010 cost was escalated to 2007 dollars using the GDP chain-type price index from AEO 2007, resulting in a delivered 2010 price in 2007 dollars of $6.40/MMkJ ($6.75/MMBtu). [3]

2.4 ENVIRONMENTAL TARGETS

The environmental targets for the study were considered on a technology- and fuel-specific basis. In setting the environmental targets a number of factors were considered, including current emission regulations, regulation trends, results from recent permitting activities and the status of current best available control technology (BACT).

The current federal regulation governing new fossil-fuel fired electric utility steam generating units is the New Source Performance Standards (NSPS) as amended in February 2006 and shown in Exhibit 2-5, which represents the minimum level of control that would be required for a new fossil energy plant. [5] Stationary combustion turbine emission limits are further defined in 40 CFR Part 60, Subpart KKKK.

Exhibit 2-5 Standards of Performance for Electric Utility Steam Generating Units Built, Reconstructed, or Modified After February 28, 2005

	New Units		Reconstructed Units		Modified Units	
	Emission Limit	% Reduction	Emission Limit (lb/MMBtu)	% Reduction	Emission Limit (lb/MMBtu)	% Reduction
PM	0.015 lb/MMBtu	99.9	0.015	99.9	0.015	99.8
SO_2	1.4 lb/MWh	95	0.15	95	0.15	90
NOx	1.0 lb/MWh	N/A	0.11	N/A	0.15	N/A

The new NSPS standards apply to units with the capacity to generate greater than 73 MW of power by burning fossil fuels, as well as cogeneration units that sell more than 25 MW of power and more than one-third of their potential output capacity to any utility power distribution system. The rule also applies to combined cycle, including IGCC plants, and combined heat and power combustion turbines that burn 75 percent or more synthetic-coal gas. In cases where both an emission limit and a percent reduction are presented, the unit has the option of meeting one or the other. All limits with the unit lb/MWh are based on gross power output.

Other regulations that could affect emissions limits from a new plant include the New Source Review (NSR) permitting process and Prevention of Significant Deterioration (PSD). The NSR process requires installation of emission control technology meeting either BACT determinations for new sources being located in areas meeting ambient air quality standards (attainment areas), or Lowest Achievable Emission Rate (LAER) technology for sources being located in areas not meeting ambient air quality standards (non-attainment areas). Environmental area designation varies by county and can be established only for a specific site location. Based on the Environmental Protection Agency (EPA) Green Book Non-attainment Area Map relatively few areas in the Midwestern U.S. are classified as “non-attainment” so the plant site for this study was assumed to be in an attainment area. [6]

In addition to federal regulations, state and local jurisdictions can impose even more stringent regulations on a new facility. However, since each new plant has unique environmental requirements, it was necessary to apply some judgment in setting the environmental targets for this study.

The Clean Air Mercury Rule (CAMR) established NSPS limits for Hg emissions from new pulverized coal-fired boilers based on coal type as well as for IGCC units independent of coal type. The NSPS limits, based on gross output, are shown in Exhibit 2-6. [7] The applicable limit in this study is 20 x 10^{-6} lb/MWh for both bituminous coal-fired PC boilers and for IGCC units.

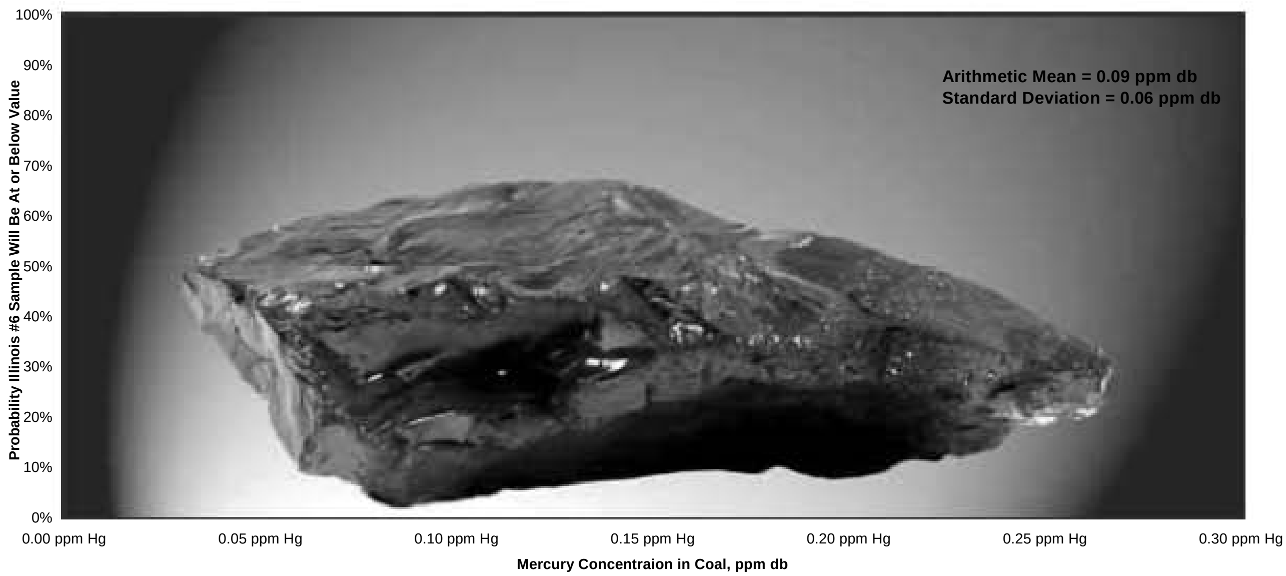
Exhibit 2-6 NSPS Mercury Emission Limits

Coal Type / Technology	Hg Emission Limit
Bituminous	**20 x 10^{-6} lb/MWh**
Subbituminous (wet units)	66 x 10^{-6} lb/MWh
Subbituminous (dry units)	97 x 10^{-6} lb/MWh
Lignite	175 x 10^{-6} lb/MWh
Coal refuse	16 x 10^{-6} lb/MWh
IGCC	**20 x 10^{-6} lb/MWh**

The mercury content of 34 samples of Illinois No. 6 coal has an arithmetic mean value of 0.09 ppm (dry basis) with standard deviation of 0.06 based on coal samples shipped by Illinois mines. [8] Hence, as illustrated in Exhibit 2-7, there is a 50 percent probability that the mercury content in the Illinois No. 6 coal would not exceed 0.09 ppm (dry basis). The coal mercury content for this study was assumed to be 0.15 ppm (dry) for all IGCC and PC cases, which corresponds to the mean plus one standard deviation and encompasses about 84 percent of the samples. It was further assumed that all of the coal Hg enters the gas phase and none leaves with the bottom ash or slag.

The current NSPS emission limits are provided below for each technology along with the environmental targets for this study and the control technologies employed to meet the targets. In some cases, application of the control technology results in emissions that are less than the target, but in no case are the emissions greater than the target.

Exhibit 2-7 Probability Distribution of Mercury Concentration in the Illinois No. 6 Coal



2.4.1 IGCC

The IGCC environmental targets were chosen to match the Electric Power Research Institute's (EPRI) design basis for their CoalFleet for Tomorrow Initiative and are shown in Exhibit 2-8. [9] EPRI notes that these are design targets and are not to be used for permitting values.

Exhibit 2-8 Environmental Targets for IGCC Cases

Pollutant	Environmental Target	NSPS Limit[1]	Control Technology
NOx	15 ppmv (dry) @ 15% O_2	1.0 lb/MWh (0.116 lb/MMBtu)	Low NOx burners and syngas nitrogen dilution
SO_2	0.0128 lb/MMBtu	1.4 lb/MWh (0.162 lb/MMBtu)	Selexol, MDEA or Sulfinol (depending on gasifier technology)
Particulate Matter (Filterable)	0.0071 lb/MMBtu	0.015 lb/MMBtu	Quench, water scrubber, and/or cyclones and candle filters (depending on gasifier technology)
Mercury	> 90% capture	20 x 10^{-6} lb/MWh (2.3 lb/TBtu)	Carbon bed

[1] The value in parentheses is calculated based on an average heat rate of 8,640 Btu/kWh from the three non-CO_2 capture gasifier cases.

Based on published vendor literature, it was assumed that low NOx burners (LNB) and nitrogen dilution can achieve 15 ppmv (dry) at 15 percent O_2, and that value was used for all IGCC cases. [10, 11]

To achieve an environmental target of 0.0128 lb/MMBtu of SO_2 requires approximately 28 ppmv sulfur in the sweet syngas. The acid gas removal (AGR) process must have a sulfur capture efficiency of about 99.7 percent to reach the environmental target. Vendor data on each of the three AGR processes used in the non-capture cases indicate that this level of sulfur removal is possible. In the CO_2 capture cases, the two-stage Selexol process was designed for 95 percent CO_2 removal which results in a sulfur capture of greater than 99.7 percent, hence the lower sulfur emissions in the CO_2 capture cases.

Most of the coal ash is removed from the gasifier as slag. The ash that remains entrained in the syngas is captured in the downstream equipment, including the syngas scrubber and a cyclone and either ceramic or metallic candle filters (CoP and Shell). The environmental target of 0.0071 lb/MMBtu filterable particulates can be achieved with each combination of particulate control devices so that in each IGCC case it was assumed the environmental target was met exactly.

The environmental target for mercury capture is greater than 90 percent. Based on experience at the Eastman Chemical plant, where syngas from a GEE gasifier is treated, the actual mercury removal efficiency used is 95 percent. Sulfur-impregnated activated carbon is used by Eastman as the adsorbent in the packed beds operated at 30°C (86°F) and 6.2 MPa (900 psig). Mercury removal between 90 and 95 percent has been reported with a bed life of 18 to 24 months. Removal efficiencies may be even higher, but at 95 percent the measurement precision limit was reached. Eastman has yet to experience any mercury contamination in its product. [12] Mercury removals of greater than 99 percent can be achieved by the use of dual beds, i.e., two beds in series. However, this study assumes that the use of sulfur-impregnated carbon in a single carbon bed achieves 95 percent reduction of mercury emissions which meets the environmental target and NSPS limits in all cases.

2.4.2 PC

BACT was applied to each of the PC cases and the resulting emissions compared to NSPS limits and recent permit averages. Since the BACT results met or exceeded the NSPS requirements and the average of recent permits, they were used as the environmental targets as shown in Exhibit 2-9. The average of recent permits is comprised of 8 units at 5 locations. The 5 plants include Elm Road Generating Station, Longview Power, Prairie State, Thoroughbred and Cross.

It was assumed that LNBs and staged overfire air (OFA) would limit NOx emissions to 0.5 lb/MMBtu and that selective catalytic reduction (SCR) technology would be 86 percent efficient, resulting in emissions of 0.07 lb/MMBtu for all cases.

The wet limestone scrubber was assumed to be 98 percent efficient which results in SO_2 emissions of 0.085 lb/MMBtu. Current technology allows flue gas desulfurization (FGD) removal efficiencies in excess of 99 percent, but based on NSPS requirements and recent permit averages, such high removal efficiency is not necessary.

The fabric filter used for particulate control was assumed to be 99.8 percent efficient. The result is particulate emissions of 0.013 lb/MMBtu in all cases, which also exceeds NSPS and recent permit average requirements.

Exhibit 2-9 Environmental Targets for PC Cases

Pollutant	Environmental Target	NSPS Limit	Average of Recent Permits	Control Technology
NOx	0.07 lb/MMBtu	1.0 lb/MWh (0.111 lb/MMBtu)	0.08 lb/MMBtu	Low NOx burners, overfire air and SCR
SO_2	0.085 lb/MMBtu	1.4 lb/MWh (0.156 lb/MMBtu)	0.16 lb/MMBtu	Wet limestone scrubber
Particulate Matter (Filterable)	0.013 lb/MMBtu	0.015 lb/MMBtu	0.017 lb/MMBtu	Fabric filter
Mercury	1.14 lb/TBtu	20 x 10^{-6} lb/MWh (2.2 lb/TBtu)	2.49 lb/TBtu	Co-benefit capture

Mercury control for PC cases was assumed to occur through 90 percent co-benefit capture in the fabric filter and the wet FGD scrubber. EPA used a statistical method to calculate the Hg co-benefit capture from units using a "best demonstrated technology" approach, which for bituminous coals was considered to be a combination of a fabric filter and an FGD system. The statistical analysis resulted in a co-benefit capture estimate of 86.7 percent with an efficiency range of 83.8 to 98.8 percent. [13] EPA's documentation for their Integrated Planning Model (IPM) provides mercury emission modification factors (EMF) based on 190 combinations of boiler types and control technologies. The EMF is simply one minus the removal efficiency. For PC boilers (as opposed to cyclones, stokers, fluidized beds and 'others') with a fabric filter, SCR and wet FGD, the EMF is 0.1 which corresponds to a removal efficiency of 90 percent. [14] The average reduction in total Hg emissions developed from EPA's Information Collection Request (ICR) data on U.S. coal-fired boilers using bituminous coal, fabric filters and wet FGD is 98 percent. [15] The referenced sources bound the co-benefit Hg capture for bituminous coal units employing SCR, a fabric filter and a wet FGD system between 83.8 and 98 percent. Ninety percent was chosen as near the mid-point of this range and it also matches the value used by EPA in their IPM.

Since co-benefit capture alone exceeds the requirements of NSPS and recent permit averages, no activated carbon injection is included in this study.

2.4.3 NGCC

BACT was applied to the NGCC cases and the resulting emissions compared to NSPS limits. The NGCC environmental targets were chosen based on reasonably obtainable limits given the control technologies employed and are presented in Exhibit 2-10.

Exhibit 2-10 Environmental Targets for NGCC Cases

Pollutant	Environmental Target	40 CFR Part 60, Subpart KKKK Limits	Control Technology
NOx	2.5 ppmv @ 15% O_2	15 ppmv @ 15% O_2	Low NOx burners and SCR
SO_2	Negligible	0.9 lb/MWh (0.135 lb/MMBtu)[1]	Low sulfur content fuel
Particulate Matter (Filterable)	N/A	N/A	N/A
Mercury	N/A	N/A	N/A

[1] Assumes a heat rate of 6,690 Btu/kWh.

Published vendor literature indicates that 25 ppmv NOx at 15 percent O_2 is achievable using natural gas and dry low NOx (DLN) technology. [16, 17] The application of SCR with 90 percent efficiency further reduces NOx emissions to 2.5 ppmv, which was selected as the environmental target.

For the purpose of this study, natural gas was assumed to contain a negligible amount of sulfur compounds, and therefore generate negligible sulfur emissions. The EPA defines pipeline natural gas as containing >70 percent methane by volume or having a gross calorific value of between 35.4 and 40.9 MJ/Nm^3 (950 and 1,100 Btu/scf) and having a total sulfur content of less than 13.7 mg/Nm^3 (0.6 gr/100 scf). [18] Assuming a sulfur content equal to the EPA limit for pipeline natural gas, resulting SO_2 emissions for the two NGCC cases in this study would be 21 tonnes/yr (23.2 tons/yr) at 85 percent capacity factor or 0.00084 kg/GJ (0.00195 lb/MMBtu). Thus for the purpose of this study, SO_2 emissions were considered negligible.

The pipeline natural gas was assumed to contain no particulate matter and no mercury resulting in no emissions of either.

2.4.4 CARBON DIOXIDE

Carbon dioxide (CO_2) is not currently regulated. However, the possibility exists that carbon limits will be imposed in the future and this study examines cases that include a reduction in CO_2 emissions. Because the form of emission limits, should they be imposed, is not known, CO_2 emissions are reported on both a lb/(gross) MWh and lb/(net) MWh basis in each capture case emissions table.

For the IGCC cases that have CO_2 capture, the basis is a nominal 90 percent removal based on carbon input from the coal and excluding carbon that exits the gasifier with the slag. The minimum number of water gas shift reactors was used with a maximum Selexol CO_2 removal efficiency of 95 percent (based on a vendor quote) to achieve an overall CO_2 removal efficiency of 90 percent. Once the number of shift reactors was determined, the Selexol removal efficiency was decreased from 95 percent if possible while still meeting the 90 percent overall target. In the case of the E-Gas™ gasifier, CO_2 capture is limited to 88.4 percent because of the relatively high methane content in the syngas that is not converted to CO_2 in the shift reactors.

For PC and NGCC cases that have CO_2 capture, it is assumed that all of the fuel carbon is converted to CO_2 in the flue gas. CO_2 is also generated from limestone in the FGD system, and 90 percent of the CO_2 exiting the FGD absorber is subsequently captured using the Econamine FG Plus technology.

The cost of CO_2 capture was calculated in two ways, the cost of CO_2 removed and the cost of CO_2 avoided, as illustrated in Equations 1 and 2, respectively. The cost of electricity in the CO_2 capture cases includes transport, storage and monitoring (TS&M) as well as capture and compression.

$$(1) \qquad Removal\ Cost = \frac{\{LCOE_{with\ removal} - LCOE_{w/o\ removal}\}\ \$/MWh}{\{CO_2\ removed\}\ tons/MWh}$$

$$(2) \qquad Avoided\ Cost = \frac{\{LCOE_{with\ removal} - LCOE_{w/o\ removal}\}\ \$/MWh}{\{Emissions_{w/o\ removal} - Emissions_{with\ removal}\}\ tons/MWh}$$

2.5 CAPACITY FACTOR

This study assumes that each new plant would be dispatched any time it is available and would be capable of generating maximum capacity when online. Therefore capacity factor and availability are equal. The availability for PC and NGCC cases was determined using the Generating Availability Data System (GADS) from the North American Electric Reliability Council (NERC). [19] Since there are only two operating IGCC plants in North America, the same database was not useful for determining IGCC availability. Rather, input from EPRI and their work on the CoalFleet for Tomorrow Initiative was used.

NERC defines an equivalent availability factor (EAF), which is essentially a measure of the plant capacity factor assuming there is always a demand for the output. The EAF accounts for planned and scheduled derated hours as well as seasonal derated hours. As such, the EAF matches this study's definition of capacity factor.

The average EAF for coal-fired plants in the 400-599 MW size range was 84.9 percent in 2004 and averaged 83.9 percent from 2000-2004. Given that many of the plants in this size range are older, the EAF was rounded up to 85 percent and that value was used as the PC plant capacity factor.

The average EAF for NGCC plants in the 400-599 MW size range was 84.7 percent in 2004 and averaged 82.7 percent from 2000-2004. Using the same rationale as for PC plants, the EAF was rounded up to 85 percent and that value was also used as the NGCC plant capacity factor.

EPRI examined the historical forced and scheduled outage times for IGCCs and concluded that the reliability factor (which looks at forced or unscheduled outage time only) for a single train IGCC (no spares) would be about 90 percent. [20] To get the availability factor, one has to deduct the scheduled outage time. In reality the scheduled outage time differs from gasifier technology-to-gasifier technology, but the differences are relatively small and would have minimal impact on the capacity factor, so for this study it was assumed to be constant at a 30-day planned outage per year (or two 15-day outages). The planned outage would amount to 8.2 percent of the year, so the availability factor would be (90 percent - 8.2 percent), or 81.2 percent.

There are four operating IGCC's worldwide that use a solid feedstock and are primarily power producers (Polk, Wabash, Buggenum and Puertollano). A 2006 report by Higman et al. examined the reliability of these IGCC power generation units and concluded that typical annual on-stream times are around 80 percent. [21] The capacity factor would be somewhat less than the on-stream time since most plants operate at less than full load for some portion of the operating year. Given the results of the EPRI study and the Higman paper, a capacity factor of 80 percent was chosen for IGCC with no spare gasifier required.

The addition of CO_2 capture to each technology was assumed not to impact the capacity factor. This assumption was made to enable a comparison based on the impact of capital and variable operating costs only. Any reduction in assumed capacity factor would further increase the LCOE for the CO_2 capture cases.

2.6 RAW WATER USAGE

A water balance was performed for each case on the major water consumers in the process. The total water demand for each subsystem was determined and internal recycle water available from various sources like boiler feedwater blowdown and condensate from syngas or flue gas (in CO_2 capture cases) was applied to offset the water demand. The difference between demand and recycle is raw water usage.

Raw water makeup was assumed to be provided 50 percent by a publicly owned treatment works (POTW) and 50 percent from groundwater. Raw water usage is defined as the water metered from a raw water source and used in the plant processes for any and all purposes, such as cooling tower makeup, boiler feedwater makeup, slurry preparation makeup, ash handling makeup, syngas humidification, quench system makeup, and FGD system makeup. Usage represents the overall impact of the process on the water source.

The largest consumer of raw water in all cases is cooling tower makeup. It was assumed that all cases utilized a mechanical draft, evaporative cooling tower, and all process blowdown streams were assumed to be treated and recycled to the cooling tower. The design ambient wet bulb temperature of 11°C (51.5°F) (Exhibit 2-1) was used to achieve a cooling water temperature of 16°C (60°F) using an approach of 5°C (8.5°F). The cooling water range was assumed to be 11°C (20°F). The cooling tower makeup rate was determined using the following [22]:

- Evaporative losses of 0.8 percent of the circulating water flow rate per 10°F of range
- Drift losses of 0.001 percent of the circulating water flow rate
- Blowdown losses were calculated as follows:
    - Blowdown Losses = Evaporative Losses / (Cycles of Concentration - 1)

      Where cycles of concentration is a measure of water quality, and a mid-range value of 4 was chosen for this study.

The water balances presented in subsequent sections include the water demand of the major water consumers within the process, the amount provided by internal recycle, and by difference, the amount of raw water required.

2.7 COST ESTIMATING METHODOLOGY

The Total Plant Cost (TPC) and Operation and Maintenance (O&M) costs for each of the cases in the study were estimated by WorleyParsons Group Inc. (WorleyParsons). The estimates carry an accuracy of ±30 percent, consistent with the screening study level of information available for the various study power technologies.

WorleyParsons used an in-house database and conceptual estimating models for the capital cost and O&M cost estimates. Costs were further calibrated using a combination of adjusted vendor-furnished and actual cost data from recent design and design/build projects.

The capital costs for each cost account were reviewed by comparing individual accounts across all of the other cases and technologies to ensure an accurate representation of the relative cost differences between the cases and accounts.

All capital and O&M costs are presented as "overnight costs" expressed in December 2006 dollars. In this study the first year of plant construction is assumed to be 2007, and the resulting LCOE is expressed in year 2007 dollars. The capital and operating costs in December 2006 dollars were treated as a January 2007 year cost throughout the report without escalation. In this report December 2006 dollars and January 2007 dollars are considered to be equal.

Capital costs are presented at the TPC level. TPC includes:

- Equipment (complete with initial chemical and catalyst loadings),
- Materials,
- Labor (direct and indirect),
- Engineering and construction management, and
- Contingencies (process and project).

Owner's costs are excluded.

System Code-of-Accounts

The costs are grouped according to a process/system oriented code of accounts. This type of code-of-account structure has the advantage of grouping all reasonably allocable components of a system or process so they are included in the specific system account. (This would not be the case had a facility, area, or commodity account structure been chosen instead).

Non-CO_2 Capture Plant Maturity

The case estimates provided include technologies at different commercial maturity levels. The estimates for the non-CO_2-capture PC and NGCC cases represent well-developed commercial technology or "n^{th} plants." The non-capture IGCC cases are also based on commercial offerings, however, there have been very limited sales of these units so far. These non-CO_2-capture IGCC plant costs are less mature in the learning curve, and the costs listed reflect the "next commercial offering" level of cost rather than mature n^{th}-of-a-kind cost. Thus, each of these cases reflects the expected cost for the next commercial sale of each of these respective technologies.

CO_2 Removal Maturity

The post-combustion CO_2 removal technology for the PC and NGCC capture cases is immature technology. This technology remains unproven at commercial scale in power generation applications.

The pre-combustion CO_2 removal technology for the IGCC capture cases has a stronger commercial experience base. Pre-combustion CO_2 removal from syngas streams has been proven in chemical processes with similar conditions to that in IGCC plants, but has not been demonstrated in IGCC applications. While no commercial IGCC plant yet uses CO_2 removal technology in commercial service, there are currently IGCC plants with CO_2 capture well along in the planning stages.

Contracting Strategy

The estimates are based on an Engineering/Procurement/Construction Management (EPCM) approach utilizing multiple subcontracts. This approach provides the Owner with greater control of the project, while minimizing, if not eliminating most of the risk premiums typically included in an Engineer/Procure/Construct (EPC) contract price.

In a traditional lump sum EPC contract, the Contractor assumes all risk for performance, schedule, and cost. However, as a result of current market conditions, EPC contractors appear more reluctant to assume that overall level of risk. Rather, the current trend appears to be a modified EPC approach where much of the risk remains with the Owner. Where Contractors are willing to accept the risk in EPC type lump-sum arrangements, it is reflected in the project cost. In today's market, Contractor premiums for accepting these risks, particularly performance risk, can be substantial and increase the overall project costs dramatically.

The EPCM approach used as the basis for the estimates here is anticipated to be the most cost effective approach for the Owner. While the Owner retains the risks, the risks become reduced with time, as there is better scope definition at the time of contract award(s).

Estimate Scope

The estimates represent a complete power plant facility on a generic site. Site-specific considerations such as unusual soil conditions, special seismic zone requirements, or unique local conditions such as accessibility, local regulatory requirements, etc. are not considered in the estimates.

The estimate boundary limit is defined as the total plant facility within the "fence line" including coal receiving and water supply system, but terminating at the high voltage side of the main power transformers. The single exception to the fence line limit is in the CO_2 capture cases where costs are included for TS&M of the CO_2.

Labor costs are based on Merit Shop (non-union), in a competitive bidding environment.

Capital Costs

WorleyParsons developed the capital cost estimates for each plant using the company's in-house database and conceptual estimating models for each of the specific technologies. This database and the respective models are maintained by WorleyParsons as part of a commercial power plant design base of experience for similar equipment in the company's range of power and process projects. A reference bottoms-up estimate for each major component provides the basis for the estimating models. This provides a basis for subsequent comparisons and easy modification when comparing between specific case-by-case variations.

Key equipment costs for each of the cases were calibrated to reflect recent quotations and/or purchase orders for other ongoing in-house power or process projects. These include, but are not limited to the following equipment:

- Pulverized Coal Boilers
- Combustion Turbine Generators
- Steam Turbine Generators
- Circulating Water Pumps and Drivers
- Cooling Towers
- Condensers
- Air Separation Units (partial)
- Main Transformers
- Econamine FG Plus CO_2 Capture Process (quote provided specifically for this project)

Other key estimate considerations include the following:

- Labor costs are based on Midwest, Merit Shop. Costs would need to be re-evaluated for projects at different locations or for projects employing union labor.
- The estimates are based on a competitive bidding environment, with adequate skilled craft labor available locally.
- Labor is based on a 50-hour work-week (5-10s). No additional incentives such as per-diems or bonuses have been included to attract craft labor.
- While not included at this time, labor incentives may ultimately be required to attract and retain skilled labor depending on the amount of competing work in the region, and the availability of skilled craft in the area at the time the projects proceed to construction. Current indications are that regional craft shortages are likely over the next several years. The types and amounts of incentives will vary based on project location and timing relative to other work. The cost impact resulting from an inadequate local work force can be significant.
- The estimates are based on a greenfield site.
- The site is considered to be Seismic Zone 1, relatively level, and free from hazardous materials, archeological artifacts, or excessive rock. Soil conditions are considered adequate for spread footing foundations. The soil bearing capability is assumed adequate such that piling is not needed to support the foundation loads.
- Costs are limited to within the “fence line,” terminating at the high voltage side of the main power transformers with the exception of costs included for TS&M of CO_2 in all capture cases.

- Engineering and Construction Management were estimated as a percent of bare erected cost; 10 percent for IGCC and PC technologies, and 9 percent for NGCC technologies. These costs consist of all home office engineering and procurement services as well as field construction management costs. Site staffing generally includes a construction manager, resident engineer, scheduler, and personnel for project controls, document control, materials management, site safety and field inspection.
- All capital costs are presented as "Overnight Costs" in December 2006 dollars. As previously mentioned, December 2006 and January 2007 dollars are considered equivalent in this report. Escalation to period-of-performance is specifically excluded.

Price Escalation

A significant change in power plant cost occurred in recent years due to the significant increases in the pricing of equipment and bulk materials. This estimate includes these increases. All vendor quotes used to develop these estimates were received within the last two years. The price escalation of vendor quotes incorporated a vendor survey of actual and projected pricing increases from 2004 through the third quarter of 2006 that WorleyParsons conducted for a recent project. The results of that survey were used to validate/recalibrate the corresponding escalation factors used in the conceptual estimating models.

Cross-comparisons

In all technology comparison studies, the relative differences in costs are often more significant than the absolute level of TPC. This requires cross-account comparison between technologies to review the consistency of the direction of the costs. As noted above, the capital costs were reviewed and compared across all of the cases, accounts, and technologies to ensure that a consistent representation of the relative cost differences is reflected in the estimates.

In performing such a comparison, it is important to reference the technical parameters for each specific item, as these are the basis for establishing the costs. Scope or assumption differences can quickly explain any apparent anomalies. There are a number of cases where differences in design philosophy occur. Some key examples are:

- The combustion turbine account in the GEE IGCC cases includes a syngas expander which is not required for the CoP or Shell cases.
- The combustion turbines for the IGCC capture cases include an additional cost for firing a high hydrogen content fuel.
- The Shell gasifier syngas cooling configuration is different between the CO_2-capture and non-CO_2-capture cases, resulting in a significant differential in thermal duty between the syngas coolers for the two cases.

Exclusions

The capital cost estimate includes all anticipated costs for equipment and materials, installation labor, professional services (Engineering and Construction Management), and contingency. The following items are excluded from the capital costs:

- Escalation to period-of-performance

- Owner's costs – including, but not limited to land acquisition and right-of-way, permits and licensing, royalty allowances, economic development, project development costs, allowance for funds-used-during construction, legal fees, Owner's engineering, pre-production costs, furnishings, Owner's contingency, etc.
- All taxes, with the exception of payroll taxes
- Site specific considerations – including but not limited to seismic zone, accessibility, local regulatory requirements, excessive rock, piles, laydown space, etc.
- Labor incentives in excess of a 5-day/10-hour work week
- Additional premiums associated with an EPC contracting approach

Contingency

Both the project contingency and process contingency costs represent costs that are expected to be spent in the development and execution of the project that are not yet fully reflected in the design. It is industry practice to include project contingency in the TPC to cover project uncertainty and the cost of any additional equipment that would result during detailed design. Likewise, the estimates include process contingency to cover the cost of any additional equipment that would be required as a result of continued technology development.

<u>Project Contingency</u>

Project contingencies were added to each of the capital accounts to cover project uncertainty and the cost of any additional equipment that could result from detailed design. The project contingencies represent costs that are expected to occur. Each bare erected cost account was evaluated against the level of estimate detail, field experience, and the basis for the equipment pricing to define project contingency.

The capital cost estimates associated with the plant designs in this study were derived from various sources which include prior conceptual designs and actual design and construction of both process and power plants.

The Association for the Advancement of Cost Engineering (AACE) International recognizes five classes of estimates. On the surface, the level of project definition of the cases evaluated in this study would appear to fall under an AACE International Class 5 Estimate, associated with less than 2 percent project definition, and based on preliminary design methodology. However, the study cases are actually more in line with the AACE International Class 4 Estimate, which is associated with equipment factoring, parametric modeling, historical relationship factors, and broad unit cost data.

Based on the AACE International contingency guidelines as presented in NETL's "Quality Guidelines for Energy System Studies" it would appear that the overall project contingencies for the subject cases should be in the range of 30 to 40 percent. [4] However, such contingencies are believed to be too high when the basis for the cost numbers is considered. The costs have been extrapolated from an extensive data base of project costs (estimated, quoted, and actual), based on both conceptual and detailed designs for the various technologies. This information has been used to calibrate the costs in the current studies, thus improving the quality of the overall estimates. As such, the overall project contingencies should be more in the range of 15 to 20 percent based on the specific technology; with the PC and NGCC cases being at the lower end of the range, and the IGCC cases at the higher end, and the capture cases being higher than the non-capture cases.

Process Contingency

Process contingency is intended to compensate for uncertainties arising as a result of the state of technology development. Process contingencies have been applied to the estimates as follows:

- Slurry Prep and Feed – 5 percent on GE IGCC cases - systems are operating at approximately 800 psia as compared to 600 psia for the other IGCC cases
- Gasifiers and Syngas Coolers – 15 percent on all IGCC cases – next-generation commercial offering and integration with the power island
- Two Stage Selexol – 20 percent on all IGCC capture cases - unproven technology at commercial scale in IGCC service
- Mercury Removal – 5 percent on all IGCC cases – minimal commercial scale experience in IGCC applications
- CO_2 Removal System – 20 percent on all PC/NGCC capture cases - post-combustion process unproven at commercial scale for power plant applications
- Combustion Turbine Generator – 5 percent on all IGCC non-capture cases – syngas firing and ASU integration; 10 percent on all IGCC capture cases – high hydrogen firing.
- Instrumentation and Controls – 5 percent on all IGCC accounts and 5 percent on the PC and NGCC capture cases – integration issues

AACE International provides standards for process contingency relative to technology status; from commercial technology at 0 to 5 percent to new technology with little or no test data at 40 percent. The process contingencies as applied in this study are consistent with the AACE International standards.

All contingencies included in the TPC, both project and process, represent costs that are expected to be spent in the development and execution of the project.

Operations and Maintenance (O&M)

The production costs or operating costs and related maintenance expenses (O&M) pertain to those charges associated with operating and maintaining the power plants over their expected life. These costs include:

- Operating labor
- Maintenance – material and labor
- Administrative and support labor
- Consumables
- Fuel
- Waste disposal
- Co-product or by-product credit (that is, a negative cost for any by-products sold)

There are two components of O&M costs; fixed O&M, which is independent of power generation, and variable O&M, which is proportional to power generation.

Operating Labor

Operating labor cost was determined based on of the number of operators required for each specific case. The average base labor rate used to determine annual cost is $33/hr. The associated labor burden is estimated at 30 percent of the base labor rate.

Maintenance Material and Labor

Maintenance cost was evaluated on the basis of relationships of maintenance cost to initial capital cost. This represents a weighted analysis in which the individual cost relationships were considered for each major plant component or section. The exception to this is the maintenance cost for the combustion turbines, which is calculated as a function of operating hours.

It should be noted that a detailed analysis considering each of the individual gasifier components and gasifier refractory life is beyond the scope of this study. However, to address this at a high level, the maintenance factors applied to the gasifiers vary between the individual gasifier technology suppliers. The gasifier maintenance factors used for this study are as follows:

- GE – 10 percent on all gasifier components
- CoP and Shell – 7.5 percent on the gasifier and related components, and 4.5 percent on the syngas cooling.

Administrative and Support Labor

Labor administration and overhead charges are assessed at rate of 25 percent of the burdened operation and maintenance labor.

Consumables

The cost of consumables, including fuel, was determined on the basis of individual rates of consumption, the unit cost of each specific consumable commodity, and the plant annual operating hours.

Quantities for major consumables such as fuel and sorbent were taken from technology-specific heat and mass balance diagrams developed for each plant application. Other consumables were evaluated on the basis of the quantity required using reference data.

The quantities for initial fills and daily consumables were calculated on a 100 percent operating capacity basis. The annual cost for the daily consumables was then adjusted to incorporate the annual plant operating basis, or capacity factor.

Initial fills of the consumables, fuels and chemicals, are different from the initial chemical loadings, which are included with the equipment pricing in the capital cost.

Waste Disposal

Waste quantities and disposal costs were determined/evaluated similarly to the consumables. In this study both slag from the IGCC cases and fly ash and bottom ash from the PC cases are considered a waste with a disposal cost of $17.03/tonne ($15.45/ton). The carbon used for mercury control in the IGCC cases is considered a hazardous waste with disposal cost of $882/tonne ($800/ton).

Co-Products and By-Products

By-product quantities were also determined similarly to the consumables. However, due to the variable marketability of these by-products, specifically gypsum and sulfur, no credit was taken for their potential salable value. Nor were any of the technologies penalized for their potential disposal cost. That is, for this evaluation, it is assumed that the by-product or co-product value simply offset disposal costs, for a net zero in operating costs.

It should be noted that by-product credits and/or disposal costs could potentially be an additional determining factor in the choice of technology for some companies and in selecting some sites. A high local value of the product can establish whether or not added capital should be included in the plant costs to produce a particular co-product. Ash and slag are both potential by-products in certain markets, and in the absence of activated carbon injection in the PC cases, the fly ash would remain uncontaminated and have potential marketability. However, as stated above, the ash and slag are considered wastes in this study with a concomitant disposal cost.

CO_2 Transport, Storage and Monitoring

For those cases that feature CO_2 capture, the capital and operating costs for CO_2 transport, storage and monitoring (TS&M) were independently estimated by the National Energy Technology Laboratory (NETL). Those costs were converted to a levelized cost of electricity (LCOE) and combined with the plant capital and operating costs to produce an overall LCOE. The TS&M costs were levelized over a twenty-year period using the methodology described in the next subsection of this report.

CO_2 TS&M costs were estimated based on the following assumptions:

- CO_2 is supplied to the pipeline at the plant fence line at a pressure of 15.3 MPa (2,215 psia). The CO_2 product gas composition varies in the cases presented, but is expected to meet the specification described in Exhibit 2-11. [23]

Exhibit 2-11 CO_2 Pipeline Specification

Parameter	Units	Parameter Value
Inlet Pressure	MPa (psia)	15.3 (2,215)
Outlet Pressure	MPa (psia)	10.4 (1,515)
Inlet Temperature	°C (°F)	26 (79)
N_2 Concentration	ppmv	< 300
O_2 Concentration	ppmv	< 40
Ar Concentration	ppmv	< 10

- The CO_2 is transported 80 kilometers (50 miles) via pipeline to a geologic sequestration field for injection into a saline formation.
- The CO_2 is transported and injected as a supercritical fluid in order to avoid two-phase flow and achieve maximum efficiency. [24] The pipeline is assumed to have an outlet

pressure (above the supercritical pressure) of 10.4 MPa (1,515 psia) with no recompression along the way. Accordingly, CO_2 flow in the pipeline was modeled to determine the pipe diameter that results in a pressure drop of 4.8 MPa (700 psi) over an 80 kilometer (50 mile) pipeline length. [25] (Although not explored in this study, the use of boost compressors and a smaller pipeline diameter could possibly reduce capital costs for sufficiently long pipelines.) The diameter of the injection pipe will be of sufficient size that frictional losses during injection are minimal and no booster compression is required at the well-head in order to achieve an appropriate down-hole pressure.

- The saline formation is at a depth of 1,239 meters (4,055 ft) and has a permeability of 22 millidarcy (a measure of permeability defined as roughly 10^{-12} Darcy) and formation pressure of 8.4 MPa (1,220 psig). [23] This is considered an average storage site and requires roughly one injection well for each 9,360 tonnes (10,320 short tons) of CO_2 injected per day. [23] The assumed aquifer characteristics are tabulated in Exhibit 2-12.

Exhibit 2-12 Deep, Saline Aquifer Specification

Parameter	Units	Base Case
Pressure	MPa (psi)	8.4 (1,220)
Thickness	m (ft)	161 (530)
Depth	m (ft)	1,236 (4,055)
Permeability	md	22
Pipeline Distance	km (miles)	80 (50)
Injection Rate per Well	tonne (ton) CO_2/day	9,360 (10,320)

For CO_2 transport and storage, capital and O&M costs were assessed using metrics from a 2001 Battelle report. [24] These costs were scaled from the 1999-year dollars described in the report to Dec-2006-year dollars using U.S. Bureau of Labor Statistics (BLS) Producer Price Indices for the oil and gas industry and the *Chemical Engineering* Plant Cost Index. Project and process contingencies of thirty and twenty percent, respectively, were applied to the Battelle costs to cover additional costs that are expected to arise from: i) developing a more detailed project definition, and ii) using technologies that have not been well-demonstrated to date in a similar commercial application.

For CO_2 monitoring, costs were assessed using metrics for a saline formation "enhanced monitoring package" as reported in a 2004 International Energy Agency (IEA) report. [26] The IEA report presented costs for two types of saline formations: those with low and high residual gas saturations. The reported monitoring costs were higher for saline formations with low residual gas saturation, and those costs were used as the basis for this report. The IEA report calculated the present value of life-cycle monitoring costs using a ten percent discount rate. The present value cost included the initial capital cost for monitoring as well as O&M costs for monitoring over a period of eighty years (a thirty-year injection period followed by fifty years of post-injection monitoring).

For this study, the present value reported in the IEA report was adjusted from Nov-2004-year dollars to Dec-2006-year dollars using U.S. BLS Producer Price Indices for the oil and gas industry. Project and process contingencies of thirty and thirty-five percent, respectively, were applied to the IEA value to cover additional costs that are expected to arise as described above. The resulting metric used for this report is a present value of $0.176 per metric ton of CO_2 stored over a thirty-year injection period.

In accordance with the IEA's present-value, life-cycle methodology, this report levelized monitoring costs over a twenty-year period by simply applying a capital charge factor to the present value of life-cycle monitoring costs (10 percent discount rate). This approach is representative of a scenario in which the power plant owner establishes a "CO_2 Monitoring Fund" prior to plant startup that is equal to the present value of life-cycle monitoring costs. Establishing such a fund at the outset could allay concerns about the availability of funds to pay for monitoring during the post-injection period, when the plant is no longer operating. While it is recognized that other, more nuanced, approaches could be taken to levelizing eighty years of monitoring costs over a twenty-year period, the approach applied in this report was chosen because it is simple to describe and should result in a conservative (i.e., higher) estimate of the funds required.

Levelized Cost of Electricity

The revenue requirement method of performing an economic analysis of a prospective power plant has been widely used in the electric utility industry. This method permits the incorporation of the various dissimilar components for a potential new plant into a single value that can be compared to various alternatives. The revenue requirement figure-of-merit in this report is cost of electricity (COE) levelized over a 20 year period and expressed in mills/kWh (numerically equivalent to $/MWh). The 20-year LCOE was calculated using a simplified model derived from the NETL Power Systems Financial Model. [27]

The equation used to calculate LCOE is as follows:

$$LCOE_P = \frac{(CCF_P)(TPC) + [(LF_{F1})(OC_{F1}) + (LF_{F2})(OC_{F2}) + \ldots] + (CF)[(LF_{V1})(OC_{V1}) + (LF_{V2})(OC_{V2}) + \ldots]}{(CF)(MWh)}$$

where

$LCOE_P$ =	levelized cost of electricity over P years, $/MWh
P =	levelization period (e.g., 10, 20 or 30 years)
CCF =	capital charge factor for a levelization period of P years
TPC =	total plant cost, $
LF_{Fn} =	levelization factor for category n fixed operating cost
OC_{Fn} =	category n fixed operating cost for the initial year of operation (but expressed in "first-year-of-construction" year dollars)
CF =	plant capacity factor

LF_{Vn} = levelization factor for category n variable operating cost

OC_{Vn} = category n variable operating cost at 100 percent capacity factor for the initial year of operation (but expressed in “first-year-of-construction” year dollars)

MWh = annual net megawatt-hours of power generated at 100 percent capacity factor

All costs are expressed in “first-year-of-construction” year dollars, and the resulting LCOE is also expressed in “first-year-of-construction” year dollars. In this study the first year of plant construction is assumed to be 2007, and the resulting LCOE is expressed in year 2007 dollars. The capital cost in December 2006 dollars was treated as a 2007 year cost.

In CO_2 capture cases, the LCOE for TS&M costs was added to the LCOE calculated using the above equation to generate a total cost including CO_2 capture, sequestration and subsequent monitoring.

Although their useful life is usually well in excess of thirty years, a twenty-year levelization period is typically used for large energy conversion plants and is the levelization period used in this study.

The technologies modeled in this study were divided into one of two categories for calculating LCOE: investor owned utility (IOU) high risk and IOU low risk. All IGCC cases as well as PC and NGCC cases with CO_2 capture are considered high risk. The non-capture PC and NGCC cases are considered low risk. The resulting capital charge factor and levelization factors are shown in Exhibit 2-13.

Exhibit 2-13 Economic Paramenters for LCOE Calculation

	High Risk	Low Risk	Nominal Escalation, %[1]
Capital Charge Factor	0.175	0.164	N/A
Coal Levelization Factor	1.2022	1.2089	2.35
Natural Gas Levelization Factor	1.1651	1.1705	1.96
General O&M Levelization Factor	1.1568	1.1618	1.87

[1] Nominal escalation is the real escalation plus the general annual average inflation rate of 1.87 percent.

The economic assumptions used to derive the capital charge factors are shown in Exhibit 2-14. The difference between the high risk and low risk categories is manifested in the debt-to-equity ratio and the weighted cost of capital. The values used to generate the capital charge factors and levelization factors in this study are shown in Exhibit 2-15.

Exhibit 2-14 Parameter Assumptions for Capital Charge Factors

Parameter	Value
Income Tax Rate	38% (Effective 34% Federal, 6% State)
Repayment Term of Debt	15 years
Grace Period on Debt Repayment	0 years
Debt Reserve Fund	None
Depreciation	20 years, 150% declining balance
Working Capital	zero for all parameters
Plant Economic Life	30 years
Investment Tax Credit	0%
Tax Holiday	0 years
Start-Up Costs (% of EPC)[1]	2%
All other additional capital costs ($)	0
EPC escalation	0%
Duration of Construction	3 years

[1] EPC costs equal total plant costs less contingencies

Exhibit 2-15 Financial Structure for Investor Owned Utility High and Low Risk Projects

Type of Security	% of Total	Current (Nominal) Dollar Cost	Weighted Current (Nominal) Cost	After Tax Weighted Cost of Capital
Low Risk				
Debt	50	9%	4.5%	2.79%
Equity	50	12%	6%	6%
Total			11%	8.79%
High Risk				
Debt	45	11%	4.95%	3.07%
Equity	55	12%	6.6%	6.6%
Total			11.55%	9.67%

2.8 IGCC STUDY COST ESTIMATES COMPARED TO INDUSTRY ESTIMATES

The estimated TPC for IGCC cases in this study ranges from $1,733kW to $1,977/kW for non-$CO_2$ capture cases and $2,390/kW to $2,668/kW for capture cases. Plant size ranges from 623 - 636 MW (net) for non-capture cases and 517 - 556 MW (net) for capture cases.

Within the power industry there are several power producers interested in pursuing construction of an IGCC plant. While these projects are still in the relatively early stages of development, some cost estimates have been published. Published estimates tend to be limited in detail, leaving it to the reader to speculate as to what is contained within the estimate. Published estimates for gasification plants consisting of two gasifier trains range from $2,206/kW to $3,175/kW. [28, 29] Corresponding plant sizes range from 600 - 680 MW. Since none of the published estimates state that CO_2 capture is included, it is assumed that they do not include CO_2 capture or compression equipment.

In comparing costs published in this study to those published by industry, it is important to recognize that the estimates contained in this study are based on a very specific set of criteria for the purpose of comparing the various technologies. Site specific costs and owner's costs are not included in this report. Excluding these costs is appropriate for a government-sponsored analysis as owner's costs often include varying levels of profits depending on the current market. For example, there is presently a shortage of qualified EPC companies for constructing new power plants, so these companies can demand a very high price for their services. Endorsing these historically high rates as being reasonable, or even attempting to predict them, especially since it may represent a very short-lived market imbalance, is not an appropriate role for the government. These costs, however, are generally included in industry-published estimates.

<u>Differences in Cost Estimates</u>

Project Scope

For this report, the scope of work is generally limited to work inside the project "fence line". For outgoing power, the scope stops at the high side terminals of the Generator Step-up Transformers (GSU's).

Some typical examples of items outside the fenceline include:

- New access roads and railroad tracks
- Upgrades to existing roads to accommodate increased traffic
- Makeup water pipe outside the fenceline
- Landfill for on-site waste (slag) disposal
- Natural gas line for backup fuel provisions
- Plant switchyard
- Electrical transmission lines & substation

Estimates in this report are based on a generic mid-western greenfield site having "normal" characteristics. Accordingly, the estimates do not address items such as:

- Piles or caissons
- Rock removal
- Excessive dewatering
- Expansive soil considerations
- Excessive seismic considerations
- Extreme temperature considerations
- Hazardous or contaminated soils
- Demolition or relocation of existing structures
- Leasing of offsite land for parking or laydown

- Busing of craft to site
- Costs of offsite storage

This report is based on a reasonably “standard” plant. No unusual or extraordinary process equipment is included such as:

- Excessive water treatment equipment
- Air-cooled condenser
- Automated coal reclaim
- Zero Liquid Discharge equipment
- Selective catalytic reduction catalyst

For non-capture cases, which are likely the most appropriate comparison against industry published estimates, this report is based on plant equipment sized for non-capture only. None of the equipment is sized to accommodate a future conversion to CO_2 capture.

Labor

This report is based on Merit Shop (non-union) labor. If a project is to use Union labor, there is a strong likelihood that overall labor costs will be greater than those estimated in this report.

This report is based on a 50 hour work week, with an adequate local supply of skilled craft labor. No additional incentives such as per-diems or bonuses have been included to attract and retain skilled craft labor. The construction industry is currently experiencing severe shortages in craft labor. Accordingly, published costs likely include any anticipated labor premiums.

Contracting Methodology

The estimates in this report are based on a competitively bid, multiple subcontract approach, often referred to as EPCM. Accordingly, the estimates do not include premiums associated with an EPC approach. It is believed that, given current market conditions, the premium charged by an EPC contractor could be as much as 30 percent or more over an EPCM approach.

Escalation

All of the estimates included in this report are based on December, 2006 “overnight” costs. No escalation has been added to reflect period of performance dollars. Overall project duration for plants of this type could be as much as five years or more.

Owner’s Costs

Owner’s costs are excluded from the estimates in this report. Owner’s costs as a percentage of TPC can vary dramatically. Conceivably, owner’s costs can range from 15 to 25 percent of TPC. Typical Owner’s costs include, but are not limited to, the following:

- Permits and licensing (other than construction permits)
- Land acquisition / Rights of way costs
- Economic development
- Project development costs
- Legal fees
- Owner’s Engineering / Project and Construction Management Staff

- Plant operators during startup
- Electricity consumed during startup
- Fuel and reagents consumed during startup
- Transmission interconnections and upgrades
- Taxes (other than EPCM payroll taxes)
- Operating spare parts
- Furnishings for new office, warehouse and laboratory
- Financing costs

Most if not all of these cost elements are likely included in published estimates. The addition of these elements to this report would explain most, if not all, of the disparities between estimates in the report and published costs.

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3 IGCC POWER PLANTS

Six IGCC power plant configurations were evaluated and the results are presented in this section. Each design is based on a market-ready technology that is assumed to be commercially available to support startup in 2010.

The six cases are based on the GEE gasifier, the CoP E-Gas™ gasifier and the Shell gasifier, each with and without CO_2 capture. As discussed in Section 1, the net output for the six cases varies because of the constraint imposed by the fixed gas turbine output and the high auxiliary loads imparted by the CO_2 capture process.

The combustion turbine is based on an advanced F-class design. The HRSG/steam turbine cycle is 12.4 MPa/566°C/566°C (1800 psig/1050°F/1050°F) for all of the non-CO_2 capture cases and 12.4 MPa/538°C/538°C (1800 psig/1000°F/1000°F) for all of the CO_2 capture cases. The capture cases have a lower main and reheat steam temperature primarily because the turbine firing temperature is reduced to allow for a parts life equivalent to NGCC operation with a high-hydrogen content fuel, which results in a lower turbine exhaust temperature.

The evaluation scope included developing heat and mass balances and estimating plant performance. Equipment lists were developed for each design to support plant capital and operating cost estimates. The evaluation basis details, including site ambient conditions, fuel composition and environmental targets, were provided in Section 2. Section 3.1 covers general information that is common to all IGCC cases, and case specific information is subsequently presented in Sections 3.2, 3.3 and 3.4.

3.1 IGCC COMMON PROCESS AREAS

The IGCC cases have process areas which are common to each plant configuration such as coal receiving and storage, oxygen supply, gas cleanup, power generation, etc. As detailed descriptions of these process areas for each case would be burdensome and repetitious, they are presented in this section for general background information. Where there is case-specific performance information, the performance features are presented in the relevant case sections.

3.1.1 COAL RECEIVING AND STORAGE

The function of the Coal Receiving and Storage system is to unload, convey, prepare, and store the coal delivered to the plant. The scope of the system is from the trestle bottom dumper and coal receiving hoppers up to and including the slide gate valves at the outlet of the coal storage silos. Coal receiving and storage is identical for all six IGCC cases; however, coal preparation and feed are gasifier-specific.

Operation Description – The coal is delivered to the site by 100-car unit trains comprised of 91 tonne (100 ton) rail cars. The unloading is done by a trestle bottom dumper, which unloads the coal into two receiving hoppers. Coal from each hopper is fed directly into a vibratory feeder. The 8 cm x 0 (3" x 0) coal from the feeder is discharged onto a belt conveyor. Two conveyors with an intermediate transfer tower are assumed to convey the coal to the coal stacker, which transfer the coal to either the long-term storage pile or to the reclaim area. The conveyor passes under a magnetic plate separator to remove tramp iron and then to the reclaim pile.

The reclaimer loads the coal into two vibratory feeders located in the reclaim hopper under the pile. The feeders transfer the coal onto a belt conveyor that transfers the coal to the coal surge bin located in the crusher tower. The coal is reduced in size to 3 cm x 0 (1¼" x 0) by the crusher. A conveyor then transfers the coal to a transfer tower. In the transfer tower the coal is routed to the tripper, which loads the coal into one of three silos. Two sampling systems are supplied: the as-received sampling system and the as-fired sampling system. Data from the analyses are used to support the reliable and efficient operation of the plant.

3.1.2 AIR SEPARATION UNIT (ASU) CHOICE AND INTEGRATION

In order to economically and efficiently support IGCC projects, air separation equipment has been modified and improved in response to production requirements and the consistent need to increase single train output. "Elevated pressure" air separation designs have been implemented that result in distillation column operating pressures that are about twice as high as traditional plants. In this study, the main air compressor discharge pressure was set at 1.3 MPa (190 psia) compared to a traditional ASU plant operating pressure of about 0.7 MPa (105 psia). [30] For IGCC designs the elevated pressure ASU process minimizes power consumption and decreases the size of some of the equipment items. When the air supply to the ASU is integrated with the gas turbine, the ASU operates at or near the supply pressure from the gas turbine's air compressor.

Residual Nitrogen Injection

The residual nitrogen that is available after gasifier oxygen and nitrogen requirements have been met is often compressed and sent to the gas turbine. Since all product streams are being compressed, the ASU air feed pressure is optimized to reduce the total power consumption and to provide a good match with available compressor frame sizes.

Increasing the diluent flow to the gas turbine by injecting residual nitrogen from the ASU can have a number of benefits, depending on the design of the gas turbine:

- Increased diluent increases mass flow through the turbine, thus increasing the power output of the gas turbine while maintaining optimum firing temperatures for syngas operation. This is particularly beneficial for locations where the ambient temperature and/or elevation are high and the gas turbine would normally operate at reduced output.
- By mixing with the syngas or by being injected directly into the combustor, the diluent nitrogen lowers the firing temperature (relative to natural gas) and reduces the formation of NOx.

In this study, the ASU nitrogen product was used as the primary diluent with a design target of reducing the syngas lower heating value (LHV) to 4.5-4.8 MJ/Nm^3 (120-128 Btu/scf). If the amount of available nitrogen was not sufficient to meet this target, additional dilution was provided through syngas humidification, and if still more dilution was required, the third option was steam injection.

Air Integration

Integration between the ASU and the combustion turbine can be practiced by extracting some, or all, of the ASU's air requirement from the gas turbine. Medium Btu syngas streams result in a higher mass flow than natural gas to provide the same heat content to the gas turbine. Some gas turbine designs may need to extract air to maintain stable compressor or turbine operation in response to increased fuel flow rates. Other gas turbines may balance air extraction against injection of all of the available nitrogen from the ASU. The amount of air extracted can also be varied as the ambient temperature changes at a given site to optimize year-round performance.

An important aspect of air-integrated designs is the need to efficiently recover the heat of compression contained in the air extracted from the gas turbine. Extraction air temperature is normally in the range 399 - 454°C (750 - 850°F), and must be cooled to the last stage main air compressor discharge temperature prior to admission to the ASU. High-level recovery from the extracted air occurs by transferring heat to the nitrogen stream to be injected into the gas turbine with a gas-to-gas heat exchanger.

Elevated Pressure ASU Experience in Gasification

The Buggenum, Netherlands unit built for Demkolec was the first elevated-pressure, fully integrated ASU to be constructed. It was designed to produce up to 1,796 tonnes/day (1,980 TPD) of 95 percent purity oxygen for a Shell coal-based gasification unit that fuels a Siemens V94.2 gas turbine. In normal operation at the Buggenum plant the ASU receives all of its air supply from and sends all residual nitrogen to the gas turbine.

The Polk County, Florida ASU for the Tampa Electric IGCC is also an elevated-pressure, 95 percent purity oxygen design that provides 1,832 tonnes/day (2,020 TPD) of oxygen to a GEE coal-based gasification unit, which fuels a General Electric 7FA gas turbine. All of the nitrogen produced in the ASU is used in the gas turbine. The original design did not allow for air extraction from the combustion turbine. After a combustion turbine air compressor failure in January, 2005, a modification was made to allow air extraction which in turn eliminated a bottleneck in ASU capacity and increased overall power output. [31]

ASU Basis

For this study, air integration is used for the non-carbon capture cases only. In the carbon capture cases, once the syngas is diluted to the target heating value, all of the available combustion air is required to maintain mass flow through the turbine and hence maintain power output.

The amount of air extracted from the gas turbine in the non-capture cases is determined through a process that includes the following constraints:

- The combustion turbine output must be maintained at 232 MW.
- The diluted syngas must meet heating value requirements specified by a combustion turbine vendor, which ranged from 4.5-4.8 MJ/Nm^3 (120-128 Btu/scf) (LHV).

Meeting the above constraints resulted in different levels of air extraction in the three non-carbon capture cases as shown in Exhibit 3-1. It was not a goal of this project to optimize the integration of the combustion turbine and the ASU, although several recent papers have shown that providing 25-30 percent of the ASU air from the turbine compressor provides the best balance between maximizing plant output and efficiency without compromising plant availability or reliability. [32, 33]

Exhibit 3-1 Air Extracted from the Combustion Turbine and Supplied to the ASU in Non-Carbon Capture Cases

Case No.	1	3	5
Gasifier	GEE	CoP	Shell
Air Extracted from Gas Turbine, %	4.1	4.9	6.7
Air Provided to ASU, % of ASU Total	15.7	22.3	31.0

Air Separation Plant Process Description [34]

The air separation plant is designed to produce 95 mole percent O_2 for use in the gasifier. The plant is designed with two production trains, one for each gasifier. The air compressor is powered by an electric motor. Nitrogen is also recovered, compressed, and used as dilution in the gas turbine combustor. A process schematic of a typical ASU is shown in Exhibit 3-2.

The air feed to the ASU is supplied from two sources. A portion of the air is extracted from the compressor of the gas turbine (non-CO_2 capture cases only). The remaining air is supplied from a stand-alone compressor. Air to the stand-alone compressor is first filtered in a suction filter upstream of the compressor. This air filter removes particulate, which may tend to cause compressor wheel erosion and foul intercoolers. The filtered air is then compressed in the centrifugal compressor, with intercooling between each stage.

Air from the stand-alone compressor is combined with the extraction air, and the combined stream is cooled and fed to an adsorbent-based pre-purifier system. The adsorbent removes water, carbon dioxide, and C_4+ saturated hydrocarbons in the air. After passing through the adsorption beds, the air is filtered with a dust filter to remove any adsorbent fines that may be present. Downstream of the dust filter a small stream of air is withdrawn to supply the instrument air requirements of the ASU.

Regeneration of the adsorbent in the pre-purifiers is accomplished by passing a hot nitrogen stream through the off-stream bed(s) in a direction countercurrent to the normal airflow. The nitrogen is heated against extraction steam (1.7 MPa [250 psia]) in a shell and tube heat exchanger. The regeneration nitrogen drives off the adsorbed contaminants. Following regeneration, the heated bed is cooled to near normal operating temperature by passing a cool nitrogen stream through the adsorbent beds. The bed is re-pressurized with air and placed on stream so that the current on-stream bed(s) can be regenerated.

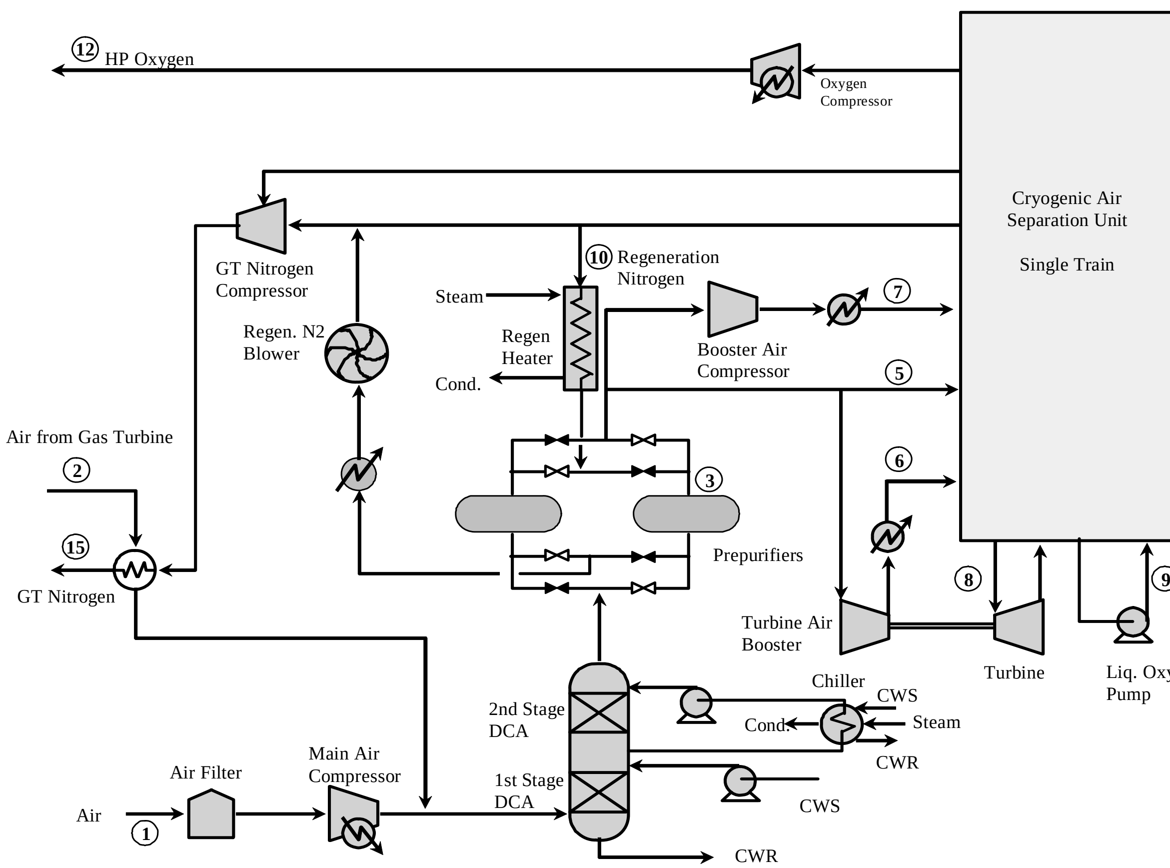
The air from the pre-purifier is then split into three streams. About 70 percent of the air is fed directly to the cold box. About 25 percent of the air is compressed in an air booster compressor. This boosted air is then cooled in an aftercooler against cooling water in the first stage and against chilled water in the second stage before it is fed to the cold box. The chiller utilizes low pressure process steam at 0.3 MPa (50 psia). The remaining 5 percent of the air is fed to a turbine-driven, single-stage, centrifugal booster compressor. This stream is cooled in a shell and tube aftercooler against cooling water before it is fed to the cold box.

All three air feeds are cooled in the cold box to cryogenic temperatures against returning product oxygen and nitrogen streams in plate-and-fin heat exchangers. The large air stream is fed directly to the first distillation column to begin the separation process. The second largest air stream is liquefied against boiling liquid oxygen before it is fed to the distillation columns. The third, smallest air stream is fed to the cryogenic expander to produce refrigeration to sustain the cryogenic separation process.

Inside the cold box the air is separated into oxygen and nitrogen products. The oxygen product is withdrawn from the distillation columns as a liquid and is pressurized by a cryogenic pump. The pressurized liquid oxygen is then vaporized against the high-pressure air feed before being warmed to ambient temperature. The gaseous oxygen exits the cold box and is fed to the centrifugal compressor with intercooling between each stage of compression. The compressed oxygen is then fed to the gasification unit.

Nitrogen is produced from the cold box at two pressure levels. Low-pressure nitrogen is split into two streams. The majority of the low-pressure nitrogen is compressed and fed to the gas turbine as diluent nitrogen. A small portion of the nitrogen is used as the regeneration gas for the pre-purifiers and recombined with the diluent nitrogen. A high-pressure nitrogen stream is also produced from the cold box and is further compressed before it is also supplied to the gas turbine.

Exhibit 3-2 Typical ASU Process Schematic



3.1.3 WATER GAS SHIFT REACTORS

Selection of Technology - In the cases with CO_2 separation and capture, the gasifier product must be converted to hydrogen-rich syngas. The first step is to convert most of the syngas carbon monoxide (CO) to hydrogen and CO_2 by reacting the CO with water over a bed of catalyst. The H_2O:CO molar ratio in the shift reaction, shown below, is adjusted to approximately 2: 1 by the addition of steam to the syngas stream thus promoting a high conversion of CO. In the cases without CO_2 separation and capture, CO shift convertors are not required.

Water Gas Shift: $CO + H_2O \leftrightarrow CO_2 + H_2$

The CO shift converter can be located either upstream of the acid gas removal step (sour gas shift) or immediately downstream (sweet gas shift). If the CO converter is located downstream of the acid gas removal, then the metallurgy of the unit is less stringent but additional equipment must be added to the process. Products from the gasifier are humidified with steam or water and contain a portion of the water vapor necessary to meet the water-to-gas criteria at the reactor inlet. If the CO converter is located downstream of the acid gas removal, then the gasifier product would first have to be cooled and the free water separated and treated. Then additional steam would have to be generated and re-injected into the CO converter feed to meet the required water-to-gas ratio. If the CO converter is located upstream of the acid gas removal step, no additional equipment is required. This is because the CO converter promotes carbonyl sulfide (COS) hydrolysis without a separate catalyst bed. Therefore, for this study the CO converter was located upstream of the acid gas removal unit and is referred to as sour gas shift (SGS).

Process Description - The SGS consists of two paths of parallel fixed-bed reactors arranged in series. Two reactors in series are used in each parallel path to achieve sufficient conversion to meet the 90 percent CO_2 capture target in the Shell and GEE gasifier cases. In the CoP case, a third shift reactor is added to each path to increase the CO conversion. Even with the third reactor added, CO_2 capture is only 88.4 percent in the CoP case because of the relatively high amount of CH_4 present in the syngas.

Cooling is provided between the series of reactors to control the exothermic temperature rise. The parallel set of reactors is required due to the high gas mass flow rate. In all three CO_2 capture cases the heat exchanger after the first SGS reactor is used to vaporize water that is then used to adjust the syngas H_2O:CO ratio to 2:1 on a molar basis. The heat exchanger after the second SGS reactor is used to raise IP steam which then passes through the reheater section of the HRSG in the GEE and CoP cases, and is used to preheat the syngas prior to the first SGS reactor in the Shell case. Approximately 96 percent conversion of the CO is achieved in the GEE and Shell cases, and about 98 percent conversion is achieved in the CoP case.

3.1.4 MERCURY REMOVAL

An IGCC power plant has the potential of removing mercury in a more simple and cost-effective manner than conventional PC plants. This is because mercury can be removed from the syngas at elevated pressure and prior to combustion so that syngas volumes are much smaller than flue gas volumes in comparable PC cases. A conceptual design for a carbon bed adsorption system was developed for mercury control in the IGCC plants being studied. Data on the performance of carbon bed systems were obtained from the Eastman Chemical Company, which uses carbon beds at its syngas facility in Kingsport, Tennessee.[12] The coal mercury content (0.15 ppm dry) and carbon bed removal efficiency (95 percent) were discussed previously in Section 2.4. IGCC-specific design considerations are discussed below.

Carbon Bed Location – The packed carbon bed vessels are located upstream of the sulfur recovery unit and syngas enters at a temperature near 38°C (100°F). Consideration was given to locating the beds further upstream before the COS hydrolysis unit (in non-CO_2 capture cases) at a temperature near 204°C (400°F). However, while the mercury removal efficiency of carbon has been found to be relatively insensitive to pressure variations, temperature adversely affects the removal efficiency. [35] Eastman Chemical also operates their beds ahead of their sulfur recovery unit at a temperature of 30°C (86°F). [12]

Consideration was also given to locating the beds downstream of the sulfur recovery unit (SRU). However, it was felt that removing the mercury and other contaminants before the sulfur recovery unit would enhance the performance of the SRU and increase the life of the various solvents.

Process Parameters – An empty vessel basis gas residence time of approximately 20 seconds was used based on Eastman Chemical's experience. [12] Allowable gas velocities are limited by considerations of particle entrainment, bed agitation, and pressure drop. One-foot-per-second superficial velocity is in the middle of the range normally encountered [35] and was selected for this application.

The bed density of 30 lb/ft^3 was based on the Calgon Carbon Corporation HGR-P sulfur-impregnated pelletized activated carbon. [36] These parameters determined the size of the vessels and the amount of carbon required. Each gasifier train has one mercury removal bed and there are two gasifier trains in each IGCC case, resulting in two carbon beds per case.

Carbon Replacement Time – Eastman Chemicals replaces its bed every 18 to 24 months. [12] However, bed replacement is not because of mercury loading, but for other reasons including:

- A buildup in pressure drop
- A buildup of water in the bed
- A buildup of other contaminants

For this study a 24 month carbon replacement cycle was assumed. Under these assumptions, the mercury loading in the bed would build up to 0.6 - 1.1 weight percent (wt%). Mercury capacity of sulfur-impregnated carbon can be as high as 20 wt%. [37] The mercury laden carbon is considered to be a hazardous waste, and the disposal cost estimate reflects this categorization.

3.1.5 ACID GAS REMOVAL (AGR) PROCESS SELECTION

Gasification of coal to generate power produces a syngas that must be treated prior to further utilization. A portion of the treatment consists of acid gas removal (AGR) and sulfur recovery. The environmental target for these IGCC cases is 0.0128 lb SO_2/MMBtu, which requires that the total sulfur content of the syngas be reduced to less than 30 ppmv. This includes all sulfur species, but in particular the total of COS and H_2S, thereby resulting in stack gas emissions of less than 4 ppmv SO_2.

COS Hydrolysis

The use of COS hydrolysis pretreatment in the feed to the acid gas removal process provides a means to reduce the COS concentration. This method was first commercially proven at the Buggenum plant, and was also used at both the Tampa Electric and Wabash River IGCC projects. Several catalyst manufacturers including Haldor Topsoe and Porocel offer a catalyst that promotes the COS hydrolysis reaction. The non-carbon capture COS hydrolysis reactor designs are based on information from Porocel. In cases with carbon capture, the SGS reactors reduce COS to H_2S as discussed in Section 3.1.3.

The COS hydrolysis reaction is equimolar with a slightly exothermic heat of reaction. The reaction is represented as follows.

$$COS + H_2O \leftrightarrow CO_2 + H_2S$$

Since the reaction is exothermic, higher conversion is achieved at lower temperatures. However, at lower temperatures the reaction kinetics are slower. Based on the feed gas for this evaluation, Porocel recommended a temperature of 177 to 204°C (350 to 400°F). Since the exit gas COS concentration is critical to the amount of H_2S that must be removed with the AGR process, a retention time of 50-75 seconds was used to achieve 99.5 percent conversion of the COS. The Porocel activated alumina-based catalyst, designated as Hydrocel 640 catalyst, promotes the COS hydrolysis reaction without promoting reaction of H_2S and CO to form COS and H_2.

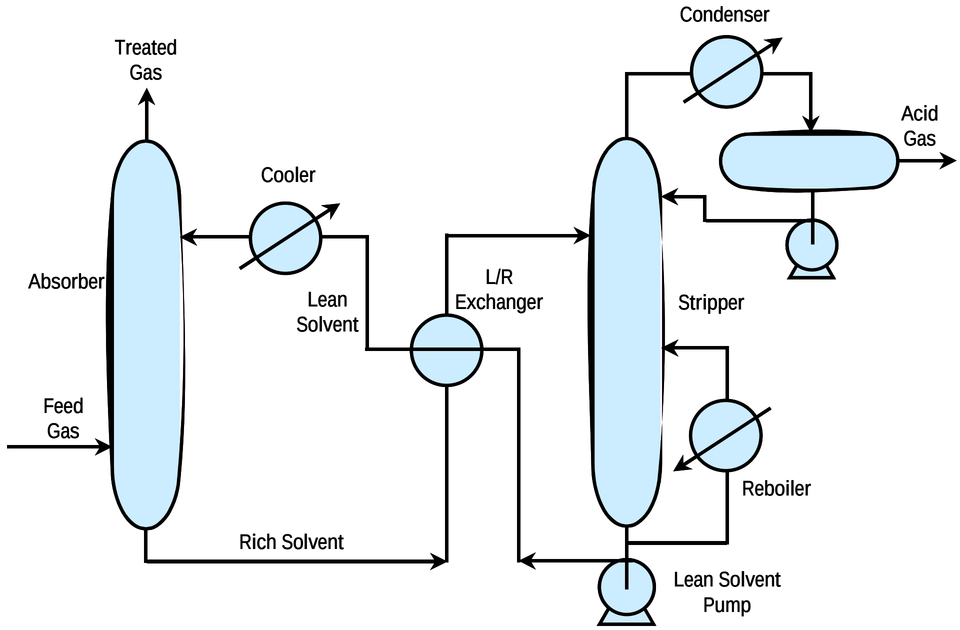
Although the reaction is exothermic, the heat of reaction is dissipated among the large amount of non-reacting components. Therefore, the reaction is essentially isothermal. The product gas, now containing less than 4 ppmv of COS, is cooled prior to entering the mercury removal process and the AGR.

Sulfur Removal

Hydrogen sulfide removal generally consists of absorption by a regenerable solvent. The most commonly used technique is based on countercurrent contact with the solvent. Acid-gas-rich solution from the absorber is stripped of its acid gas in a regenerator, usually by application of heat. The regenerated lean solution is then cooled and recirculated to the top of the absorber, completing the cycle. Exhibit 3-3 is a simplified diagram of the AGR process. [38]

There are well over 30 AGR processes in common commercial use throughout the oil, chemical, and natural gas industries. However, in a 2002 report by SFA Pacific a list of 42 operating and planned gasifiers shows that only six AGR processes are represented: Rectisol, Sulfinol, methyldiethanolamine (MDEA), Selexol, aqueous di-isoproponal (ADIP) amine and FLEXSORB. [40] These processes can be separated into three general types: chemical reagents, physical solvents, and hybrid solvents.

Exhibit 3-3 Flow Diagram for a Conventional AGR Unit



Chemical Solvents

Frequently used for acid gas removal, chemical solvents are more suitable than physical or hybrid solvents for applications at lower operating pressures. The chemical nature of acid gas absorption makes solution loading and circulation less dependent on the acid gas partial pressure. Because the solution is aqueous, co-absorption of hydrocarbons is minimal. In a conventional amine unit, the chemical solvent reacts exothermically with the acid gas constituents. They form a weak chemical bond that can be broken, releasing the acid gas and regenerating the solvent for reuse.

In recent years MDEA, a tertiary amine, has acquired a much larger share of the gas-treating market. Compared with primary and secondary amines, MDEA has superior capabilities for selectively removing H_2S in the presence of CO_2, is resistant to degradation by organic sulfur compounds, has a low tendency for corrosion, has a relatively low circulation rate, and consumes less energy. Commercially available are several MDEA-based solvents that are formulated for high H_2S selectivity.

Chemical reagents are used to remove the acid gases by a reversible chemical reaction of the acid gases with an aqueous solution of various alkanolamines or alkaline salts in water. Exhibit 3-4 lists commonly used chemical reagents along with principal licensors that use them in their processes. The process consists of an absorber and regenerator, which are connected by a circulation of the chemical reagent aqueous solution. The absorber contacts the lean solution with the main gas stream (at pressure) to remove the acid gases by absorption/ reaction with the chemical solution. The acid-gas-rich solution is reduced to low pressure and heated in the stripper to reverse the reactions and strip the acid gas. The acid-gas-lean solution leaves the bottom of the regenerator stripper and is cooled, pumped to the required pressure and recirculated back to the absorber. For some amines, a filter and a separate reclaiming section (not shown) are needed to remove undesirable reaction byproducts.

Exhibit 3-4 Common Chemical Reagents Used in AGR Processes

Chemical Reagent	Acronym	Process Licensors Using the Reagent
Monoethanolamine	MEA	Dow, Exxon, Lurgi, Union Carbide
Diethanolamine	DEA	Elf, Lurgi
Diglycolamine	DGA	Texaco, Fluor
Triethanolamine	TEA	AMOCO
Diisopropanolamine	DIPA	Shell
Methyldiethanolamine	MDEA	BASF, Dow, Elf, Snamprogetti, Shell, Union Carbide, Coastal Chemical
Hindered amine		Exxon
Potassium carbonate	“hot pot”	Eickmeyer, Exxon, Lurgi, Union Carbide

Typically, the absorber temperature is 27 to 49°C (80 to 120°F) for amine processes, and the regeneration temperature is the boiling point of the solutions, generally 104 to 127°C (220 to 260°F). The liquid circulation rates can vary widely, depending on the amount of acid gas being captured. However, the most suitable processes are those that will dissolve 2 to 10 scf acid gas per gallon of solution circulated. Steam consumption can vary widely also: 0.7 to 1.5 pounds per gallon of liquid is typical, with 0.8 to 0.9 being a typical “good” value. Case 3, which utilizes the chemical solvent MDEA, uses 0.88 pounds of steam per gallon of liquid. The steam conditions are 0.45 MPa (65 psia) and 151°C (304°F).

The major advantage of these systems is the ability to remove acid gas to low levels at low to moderate H_2S partial pressures.

Physical Solvents

Physical solvents involve absorption of acid gases into certain organic solvents that have a high solubility for acid gases. As the name implies, physical solvents involve only the physical solution of acid gas – the acid gas loading in the solvent is proportional to the acid gas partial pressure (Henry’s Law). Physical solvent absorbers are usually operated at lower temperatures than is the case for chemical solvents. The solution step occurs at high pressure and at or below ambient temperature while the regeneration step (dissolution) occurs by pressure letdown and indirect stripping with low-pressure 0.45 MPa (65 psia) steam. It is generally accepted that physical solvents become increasingly economical, and eventually superior to amine capture, as the partial pressure of acid gas in the syngas increases.

The physical solvents are regenerated by multistage flashing to low pressures. Because the solubility of acid gases increases as the temperature decreases, absorption is generally carried out at lower temperatures, and refrigeration is often required.

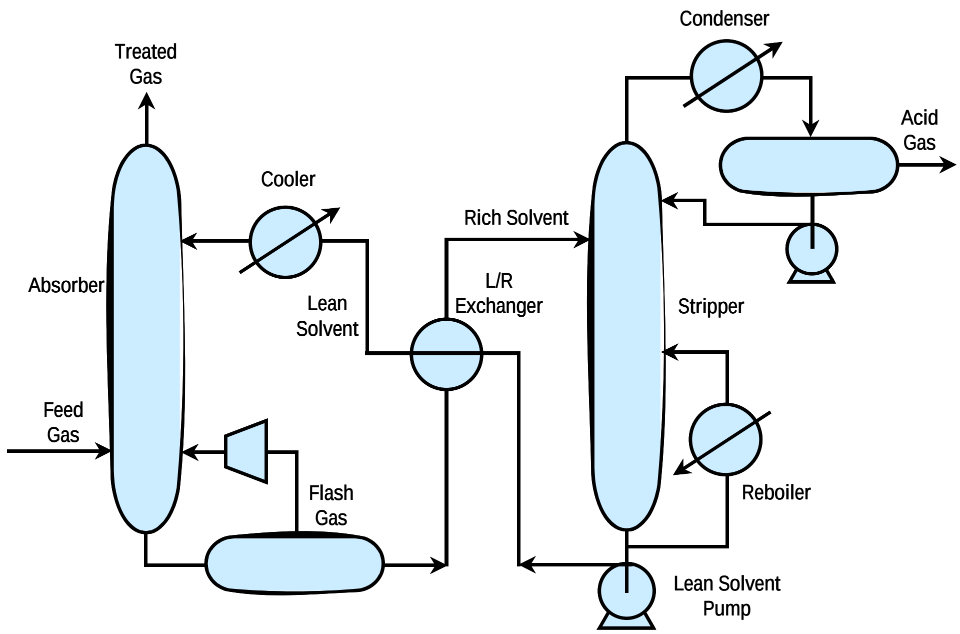
Most physical solvents are capable of removing organic sulfur compounds. Exhibiting higher solubility of H_2S than CO_2, they can be designed for selective H_2S or total acid gas removal. In applications where CO_2 capture is desired the CO_2 is flashed off at various pressures, which reduces the compression work and parasitic power load associated with sequestration.

Physical solvents co-absorb heavy hydrocarbons from the feed stream. Since heavy hydrocarbons cannot be recovered by flash regeneration, they are stripped along with the acid gas during heated regeneration. These hydrocarbon losses result in a loss of valuable product and may lead to CO_2 contamination.

Several physical solvents that use anhydrous organic solvents have been commercialized. They include the Selexol process, which uses dimethyl ether of polyethylene glycol as a solvent; Rectisol, with methanol as the solvent; Purisol, which uses N-methyl-2-pyrrolidone (NMP) as a solvent; and the propylene-carbonate process.

Exhibit 3-5 is a simplified flow diagram for a physical reagent type acid gas removal process. [38] Common physical solvent processes, along with their licensors, are listed in Exhibit 3-6.

Exhibit 3-5 Physical Solvent AGR Process Simplified Flow Diagram



Hybrid Solvents

Hybrid solvents combine the high treated-gas purity offered by chemical solvents with the flash regeneration and lower energy requirements of physical solvents. Some examples of hybrid solvents are Sulfinol, Flexsorb PS, and Ucarsol LE.

Sulfinol is a mixture of sulfolane (a physical solvent), diisopropanolamine (DIPA) or MDEA (chemical solvent), and water. DIPA is used when total acid gas removal is specified, while MDEA provides for selective removal of H_2S.

Exhibit 3-6 Common Physical Solvents Used in AGR Processes

Solvent	Solvent/Process Trade Name	Process Licensors
Dimethyl ether of poly-ethylene glycol	Selexol	UOP
Methanol	Rectisol	Linde AG and Lurgi
Methanol and toluene	Rectisol II	Linde AG
N—methyl pyrrolidone	Purisol	Lurgi
Polyethylene glycol and dialkyl ethers	Sepasolv MPE	BASF
Propylene carbonate	Fluor Solvent	Fluor
Tetrahydrothiophenedioxide	Sulfolane	Shell
Tributyl phosphate	Estasolvan	Uhde and IFP

Flexsorb PS is a mixture of a hindered amine and an organic solvent. Physically similar to Sulfinol, Flexsorb PS is very stable and resistant to chemical degradation. High treated-gas purity, with less than 50 ppmv of CO_2 and 4 ppmv of H_2S, can be achieved. Both Ucarsol LE-701, for selective removal, and LE-702, for total acid gas removal, are formulated to remove mercaptans from feed gas.

Mixed chemical and physical solvents combine the features of both systems. The mixed solvent allows the solution to absorb an appreciable amount of gas at high pressure. The amine portion is effective as a reagent to remove the acid gas to low levels when high purity is desired.

Mixed solvent processes generally operate at absorber temperatures similar to those of the amine-type chemical solvents and do not require refrigeration. They also retain some advantages of the lower steam requirements typical of the physical solvents. Common mixed chemical and physical solvent processes, along with their licensors, are listed in Exhibit 3-7. The key advantage of mixed solvent processes is their apparent ability to remove H_2S and, in some cases, COS to meet very stringent purified gas specifications.

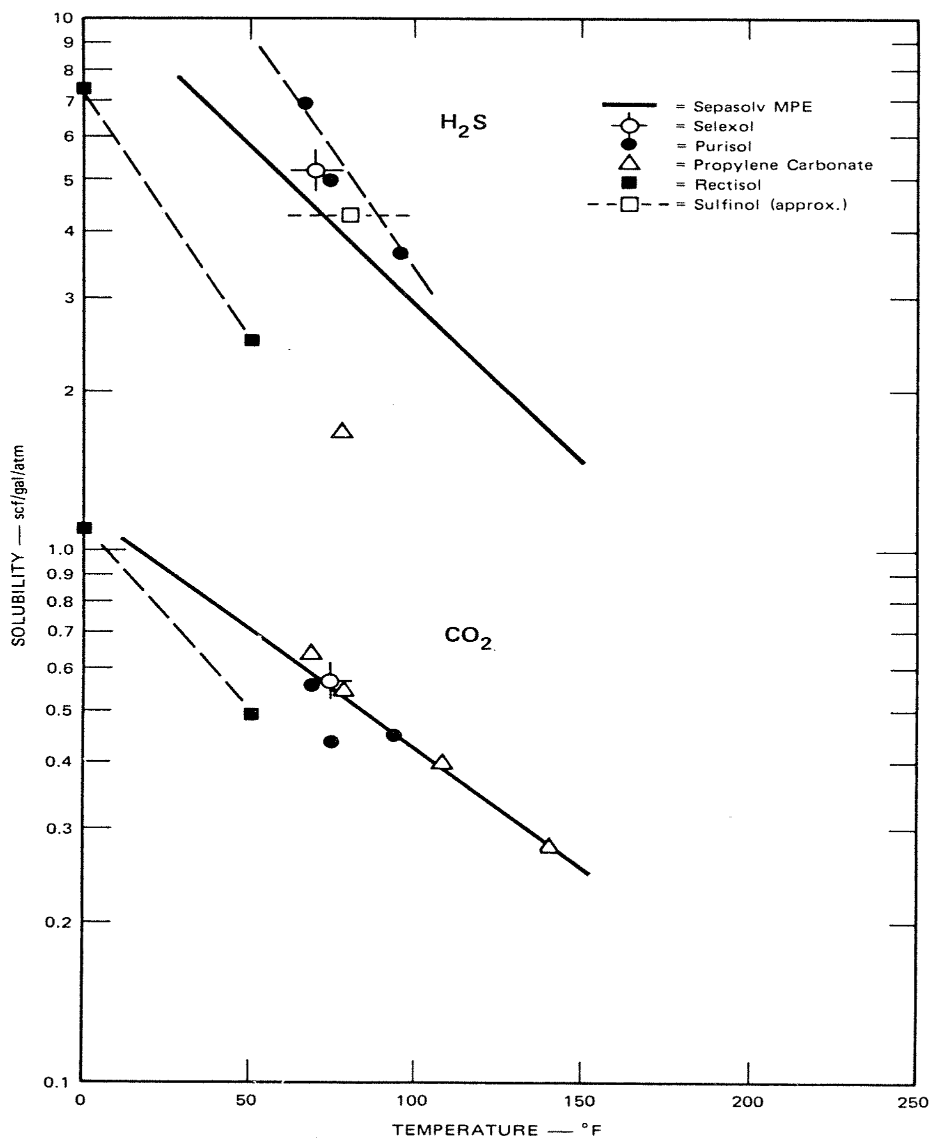
Exhibit 3-8 shows reported equilibrium solubility data for H_2S and CO_2 in various representative solvents [38]. The solubility is expressed as standard cubic feet of gas per gallon liquid per atmosphere gas partial pressure.

The figure illustrates the relative solubilities of CO_2 and H_2S in different solvents and the effects of temperature. More importantly, it shows an order of magnitude higher solubility of H_2S over CO_2 at a given temperature, which gives rise to the selective absorption of H_2S in physical solvents. It also illustrates that the acid gas solubility in physical solvents increases with lower solvent temperatures.

Exhibit 3-7 Common Mixed Solvents Used in AGR Processes

Solvent/Chemical Reagent	Solvent/Process Trade Name	Process Licensors
Methanol/MDEA or diethylamine	Amisol	Lurgi
Sulfolane/MDEA or DIPA	Sulfinol	Shell
Methanol and toluene	Selefining	Snamprogetti
(Unspecified) /MDEA	FLEXSORB PS	Exxon

Exhibit 3-8 Equilibrium Solubility Data on H_2S and CO_2 in Various Solvents



The ability of a process to selectively absorb H_2S may be further enhanced by the relative absorption rates of H_2S and CO_2. Thus, some processes, besides using equilibrium solubility differences, will use absorption rate differences between the two acid gases to achieve selectivity. This is particularly true of the amine processes where the CO_2 and H_2S absorption rates are very different.

CO_2 Capture

A two-stage Selexol process is used for all IGCC capture cases in this study. A brief process description follows.

Untreated syngas enters the first of two absorbers where H_2S is preferentially removed using loaded solvent from the CO_2 absorber. The gas exiting the H_2S absorber passes through the second absorber where CO_2 is removed using first flash regenerated, chilled solvent followed by thermally regenerated solvent added near the top of the column. The treated gas exits the absorber and is sent either directly to the combustion turbine or is partially humidified prior to entering the combustion turbine. A portion of the gas can also be used for coal drying, when required.

The amount of hydrogen recovered from the syngas stream is dependent on the Selexol process design conditions. In this study, hydrogen recovery is 99.4 percent. The minimal hydrogen slip to the CO_2 sequestration stream maximizes the overall plant efficiency. The Selexol plant cost estimates are based on a plant designed to recover this high percentage of hydrogen. For model simplification, a nominal recovery of 100 percent was used with the assumption that the additional 0.6 percent hydrogen sent to the combustion turbine would have a negligible impact on overall system performance.

The CO_2 loaded solvent exits the CO_2 absorber and a portion is sent to the H_2S absorber, a portion is sent to a reabsorber and the remainder is sent to a series of flash drums for regeneration. The CO_2 product stream is obtained from the three flash drums, and after flash regeneration the solvent is chilled and returned to the CO_2 absorber.

The rich solvent exiting the H_2S absorber is combined with the rich solvent from the reabsorber and the combined stream is heated using the lean solvent from the stripper. The hot, rich solvent enters the H_2S concentrator and partially flashes. The remaining liquid contacts nitrogen from the ASU and a portion of the CO_2 along with lesser amounts of H_2S and COS are stripped from the rich solvent. The stripped gases from the H_2S concentrator are sent to the reabsorber where the H_2S and COS that were co-stripped in the concentrator are transferred to a stream of loaded solvent from the CO_2 absorber. The clean gas from the reabsorber is combined with the clean gas from the H_2S absorber and sent to the combustion turbine.

The solvent exiting the H_2S concentrator is sent to the stripper where the absorbed gases are liberated by hot gases flowing up the column from the steam heated reboiler. Water in the overhead vapor from the stripper is condensed and returned as reflux to the stripper or exported as necessary to maintain the proper water content of the lean solvent. The acid gas from the stripper is sent to the Claus plant for further processing. The lean solvent exiting the stripper is first cooled by providing heat to the rich solvent, then further cooled by exchange with the product gas and finally chilled in the lean chiller before returning to the top of the CO_2 absorber.

AGR/Gasifier Pairings

There are numerous commercial AGR processes that could meet the sulfur environmental target of this study. The most frequently used AGR systems (Selexol, Sulfinol, MDEA, and Rectisol) have all been used with the Shell and GE gasifiers in various applications. Both existing E-Gas gasifiers use MDEA, but could in theory use any of the existing AGR technologies. [38] The following selections were made for the AGR process in non-CO_2 capture cases:

- GEE gasifier: Selexol was chosen based on the GE gasifier operating at the highest pressure (815 psia versus 615 psia for CoP and Shell) which favors the physical solvent used in the Selexol process.
- CoP gasifier: Refrigerated MDEA was chosen because the two operating E-Gas gasifiers use MDEA and because CoP lists MDEA as the selected AGR process on their website. [39] Refrigerated MDEA was chosen over conventional MDEA because the sulfur emissions environmental target chosen is just outside of the range of conventional (higher temperature) MDEA.
- Shell gasifier: The Sulfinol process was chosen for this case because it is a Shell owned technology. While the Shell gasifier can and has been used with other AGR processes, it was concluded the most likely pairing would be with the Sulfinol process.

The two-stage Selexol process is used in all three cases that require carbon capture. According to the previously referenced SFA Pacific report, "For future IGCC with CO_2 removal for sequestration, a two-stage Selexol process presently appears to be the preferred AGR process – as indicated by ongoing engineering studies at EPRI and various engineering firms with IGCC interests." [40]

3.1.6 SULFUR RECOVERY/TAIL GAS CLEANUP PROCESS SELECTION

Currently, most of the world's sulfur is produced from the acid gases coming from gas treating. The Claus process remains the mainstay for sulfur recovery. Conventional three-stage Claus plants, with indirect reheat and feeds with a high H_2S content, can approach 98 percent sulfur recovery efficiency. However, since environmental regulations have become more stringent, sulfur recovery plants are required to recover sulfur with over 99.8 percent efficiency. To meet these stricter regulations, the Claus process underwent various modifications and add-ons.

The add-on modification to the Claus plant selected for this study can be considered a separate option from the Claus process. In this context, it is often called a tail gas treating unit (TGTU) process.

The Claus Process

The Claus process converts H_2S to elemental sulfur via the following reactions:

$$H_2S + 3/2\ O_2 \leftrightarrow H_2O + SO_2$$

$$2H_2S + SO_2 \leftrightarrow 2H_2O + 3S$$

The second reaction, the Claus reaction, is equilibrium limited. The overall reaction is:

$$3H_2S + 3/2\ O_2 \leftrightarrow 3H_2O + 3S$$

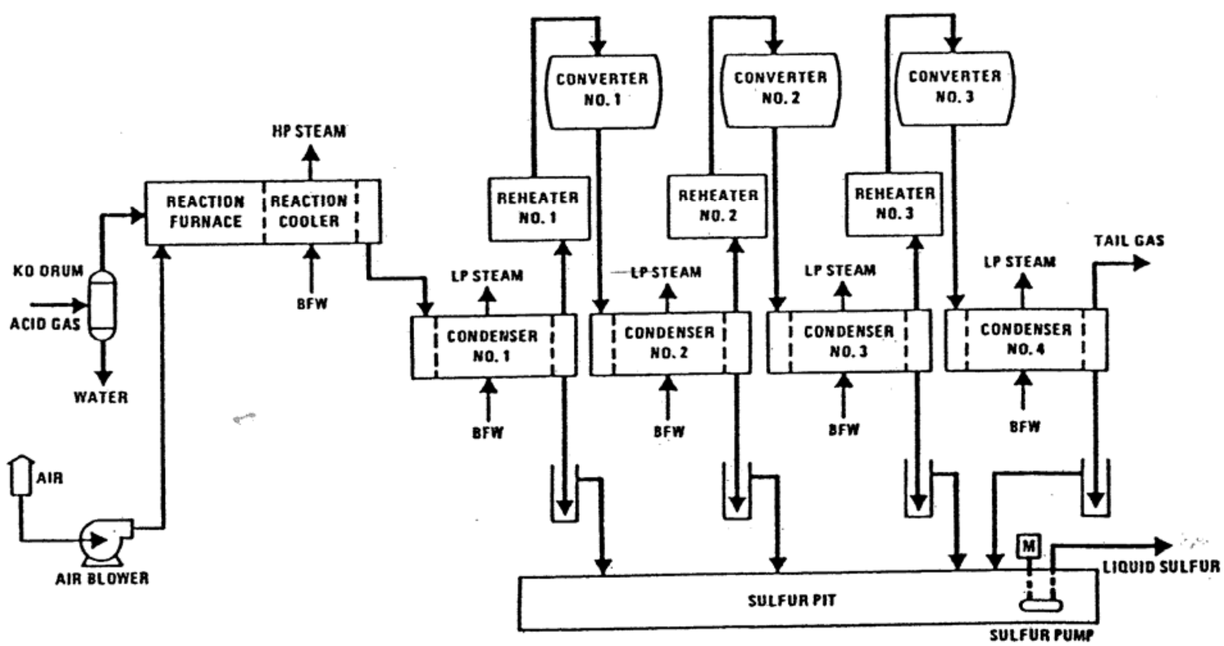
The sulfur in the vapor phase exists as S_2, S_6, and S_8 molecular species, with the S_2 predominant at higher temperatures, and S_8 predominant at lower temperatures.

A simplified process flow diagram of a typical three-stage Claus plant is shown in Exhibit 3-9. [40] One-third of the H_2S is burned in the furnace with oxygen from the air to give sufficient SO_2 to react with the remaining H_2S. Since these reactions are highly exothermic, a waste heat boiler that recovers this heat to generate high-pressure steam usually follows the furnace. Sulfur is condensed in a condenser that follows the high-pressure steam recovery section. Low-pressure steam is raised in the condenser. The tail gas from the first condenser then goes to several catalytic conversion stages, usually 2 to 3, where the remaining sulfur is recovered via the Claus reaction. Each catalytic stage consists of gas preheat, a catalytic reactor, and a sulfur condenser. The liquid sulfur goes to the sulfur pit, while the tail gas proceeds to the incinerator or for further processing in a TGTU.

Claus Plant Sulfur Recovery Efficiency

The Claus reaction is equilibrium limited, and sulfur conversion is sensitive to the reaction temperature. The highest sulfur conversion in the thermal zone is limited to about 75 percent. Typical furnace temperatures are in the range from 1093 to 1427°C (2000 to 2600°F), and as the temperature decreases, conversion increases dramatically.

Exhibit 3-9 Typical Three-Stage Claus Sulfur Plant



Claus plant sulfur recovery efficiency depends on many factors:

- H_2S concentration of the feed gas
- Number of catalytic stages
- Gas reheat method

In order to keep Claus plant recovery efficiencies approaching 94 to 96 percent for feed gases that contain about 20 to 50 percent H_2S, a split-flow design is often used. In this version of the Claus plant, part of the feed gas is bypassed around the furnace to the first catalytic stage, while the rest of the gas is oxidized in the furnace to mostly SO_2. This results in a more stable temperature in the furnace.

Oxygen-Blown Claus

Large diluent streams in the feed to the Claus plant, such as N_2 from combustion air, or a high CO_2 content in the feed gas, lead to higher cost Claus processes and any add-on or tail gas units. One way to reduce diluent flows through the Claus plant and to obtain stable temperatures in the furnace for dilute H_2S streams is the oxygen-blown Claus process.

The oxygen-blown Claus process was originally developed to increase capacity at existing conventional Claus plants and to increase flame temperatures of low H_2S content gases. The process has also been used to provide the capacity and operating flexibility for sulfur plants where the feed gas is variable in flow and composition such as often found in refineries. The application of the process has now been extended to grass roots installations, even for rich H_2S feed streams, to provide operating flexibility at lower costs than would be the case for conventional Claus units. At least four of the recently built gasification plants in Europe use oxygen enriched Claus units.

Oxygen enrichment results in higher temperatures in the front-end furnace, potentially reaching temperatures as high as 1593 to 1649°C (2900 to 3000°F) as the enrichment moves beyond 40 to 70 vol percent O_2 in the oxidant feed stream. Although oxygen enrichment has many benefits, its primary benefit for lean H_2S feeds is a stable furnace temperature. Sulfur recovery is not significantly enhanced by oxygen enrichment. Because the IGCC process already requires an ASU, the oxygen-blown Claus plant was chosen for all cases.

Tail Gas Treating

In many refinery and other conventional Claus applications, tail gas treating involves the removal of the remaining sulfur compounds from gases exiting the sulfur recovery unit. Tail gas from a typical Claus process, whether a conventional Claus or one of the extended versions of the process, usually contains small but varying quantities of COS, CS_2, H_2S, SO_2, and elemental sulfur vapors. In addition, there may be H_2, CO, and CO_2 in the tail gas. In order to remove the rest of the sulfur compounds from the tail gas, all of the sulfur-bearing species must first be converted to H_2S. Then, the resulting H_2S is absorbed into a solvent and the clean gas vented or recycled for further processing. The clean gas resulting from the hydrolysis step can undergo further cleanup in a dedicated absorption unit or be integrated with an upstream AGR unit. The latter option is particularly suitable with physical absorption solvents. The approach of treating the tail gas in a dedicated amine absorption unit and recycling the resulting acid gas to the Claus plant is the one used by the Shell Claus Off-gas Treating (SCOT) process. With tail gas treatment, Claus plants can achieve overall removal efficiencies in excess of 99.9 percent.

In the case of IGCC applications, the tail gas from the Claus plant can be catalytically hydrogenated and then recycled back into the system with the choice of location being technology dependent, or it can be treated with a SCOT-type process. In the two GEE gasifier cases the Claus plant tail gas is hydrogenated, water is separated, the tail gas is compressed and returned to the Selexol process for further treatment. GEE experience at the Polk Power Station is not relevant to this study since the acid gas is converted to sulfuric acid rather than sulfur and the tail gas, containing 150-250 ppm SO_2, is discharged through a dedicated stack. [41] In the two CoP cases the tail gas is treated in the same manner as in the GEE cases except that the recycle endpoint is the gasifier rather than the AGR process. This method is the same as practiced at the CoP Wabash River plant. [42] The two recycle points were chosen based on conversations with the gasifier technology vendors.

In the two Shell cases the Claus tail gas is catalytically hydrogenated and then treated in an amine-based tail gas cleanup process. The bulk of the H_2S in the tail gas is captured and recycled back to the Claus plant inlet gas stream. The sweet gas from the TGTU is combined with a slipstream of clean syngas and the combined stream is combusted in an incinerator. The hot, inert gases from the incinerator are used to dry the feed coal and then vented to atmosphere. Since the Shell Puertollano plant uses a combination of natural gas combustion and IP steam to dry their coal, their tail gas treatment procedure is different than employed in this study. The Claus plant tail gas is hydrogenated and recycled, but the recycle endpoint is not specified. [43]

Flare Stack

A self-supporting, refractory-lined, carbon steel flare stack is typically provided to combust and dispose of unreacted gas during startup, shutdown, and upset conditions. However, in all six IGCC cases a flare stack was provided for syngas dumping during startup, shutdown, etc. This flare stack eliminates the need for a separate Claus plant flare.

3.1.7 SLAG HANDLING

The slag handling system conveys, stores, and disposes of slag removed from the gasification process. Spent material drains from the gasifier bed into a water bath in the bottom of the gasifier vessel. A slag crusher receives slag from the water bath and grinds the material into pea-sized fragments. A slag/water slurry that is between 5 and 10 percent solids leaves the gasifier pressure boundary through either a proprietary pressure letdown device (CoP) or through the use of lockhoppers (GEE and Shell) to a series of dewatering bins.

The general aspects of slag handling are the same for all three technologies. The slag is dewatered, the water is clarified and recycled and the dried slag is transferred to a storage area for disposal. The specifics of slag handling vary among the gasification technologies regarding how the water is separated and the end uses of the water recycle streams.

In this study the slag bins were sized for a nominal holdup capacity of 72 hours of full-load operation. At periodic intervals, a convoy of slag-hauling trucks will transit the unloading station underneath the hopper and remove a quantity of slag for disposal. Approximately ten truckloads per day are required to remove the total quantity of slag produced by the plant operating at nominal rated power. While the slag is suitable for use as a component of road paving mixtures, it was assumed in this study that the slag would be landfilled at a specified cost just as the ash from the PC boiler cases is assumed to be landfilled at the same per ton cost.

3.1.8 POWER ISLAND

Combustion Turbine

The gas turbine generator selected for this application is representative of the advanced F Class turbines. This machine is an axial flow, single spool, and constant speed unit, with variable inlet guide vanes. The turbine includes advanced bucket cooling techniques, compressor aerodynamic design and advanced alloys, enabling a higher firing temperature than the previous generation machines. The standard production version of this machine is fired with natural gas and is also commercially offered for use with IGCC derived syngas, although only earlier versions of the turbine are currently operating on syngas. For the purposes of this study, it was assumed that the advanced F Class turbine will be commercially available to support a 2010 startup date on both conventional and high hydrogen content syngas representative of the cases with CO_2 capture. High H_2 fuel combustion issues like flame stability, flashback and NOx formation were assumed to be solved in the time frame needed to support deployment. However, because these are first-of-a-kind applications, process contingencies were included in the cost estimates as described in Section 2.7. Performance typical of an advanced F class turbine on natural gas at ISO conditions is presented in Exhibit 3-10.

Exhibit 3-10 Advanced F Class Combustion Turbine Performance Characteristics Using Natural Gas

	Advanced F Class
Firing Temperature Class, °C (°F)	1371+ (2500+)
Airflow, kg/s (lb/s)	431 (950)
Pressure Ratio	18.5
NOx Emissions, ppmv	25
Simple Cycle Output, MW	185
Combined cycle performance	
Net Output, MW	280
Net Efficiency (LHV), %	57.5
Net Heat Rate (LHV), kJ/kWh (Btu/kWh)	6,256 (5,934)

In this service, with syngas from an IGCC plant, the machine requires some modifications to the burner and turbine nozzles in order to properly combust the low-Btu gas and expand the combustion products in the turbine section of the machine.

The modifications to the machine include some redesign of the original can-annular combustors. A second modification involves increasing the nozzle areas of the turbine to accommodate the mass and volume flow of low-Btu fuel gas combustion products, which are increased relative to those produced when firing natural gas. Other modifications include rearranging the various auxiliary skids that support the machine to accommodate the spatial requirements of the plant general arrangement. The generator is a standard hydrogen-cooled machine with static exciter.

Combustion Turbine Package Scope of Supply

The combustion turbine (CT) is typically supplied in several fully shop-fabricated modules, complete with all mechanical, electrical and control systems as required for CT operation. Site CT installation involves module inter-connection, and linking CT modules to the plant systems. The CT package scope of supply for combined cycle application, while project specific, does not vary much from project-to-project. The typical scope of supply is presented in Exhibit 3-11.

Exhibit 3-11 Combustion Turbine Typical Scope of Supply

	System	System Scope
1.0	**ENGINE ASSEMBLY**	Coupling to Generator, Dry Chemical Exhaust Bearing Fire Protection System, Insulation Blankets, Platforms, Stairs and Ladders
1.1	Engine Assembly with Bedplate	Variable Inlet Guide, Vane System Compressor, Bleed System, Purge Air System, Bearing Seal Sir System, Combustors, Dual Fuel Nozzles Turbine Rotor Air Cooler
1.2	Walk-in acoustical enclosure	HVAC, Lighting, and Low Pressure CO_2 Fire Protection System
2.0	**MECHANICAL PACKAGE**	HVAC and Lighting, Air Compressor for Pneumatic System, Low Pressure CO_2 Fire Protection System
2.1 2.2	Lubricating Oil System and Control Oil System	Lube Oil Reservoir, Accumulators, 2x100% AC Driven Oil Pumps DC Emergency Oil Pump with Starter, 2x100% Oil Coolers, Duplex Oil Filter, Oil Temperature and Pressure Control Valves, Oil Vapor Exhaust Fans and Demister Oil Heaters Oil Interconnect Piping (SS and CS) Oil System Instrumentation Oil for Flushing and First Filling
3.0	**ELECTRICAL PACKAGE**	HVAC and Lighting, AC and DC Motor Control Centers, Generator Voltage Regulating Cabinet, Generator Protective Relay Cabinet, DC Distribution Panel, Battery Charger, Digital Control System with Local Control Panel (all control and monitoring functions as well as data logger and sequence of events recorder), Control System Valves and Instrumentation Communication link for interface with plant DCS Supervisory System, Bentley Nevada Vibration Monitoring System, Low Pressure CO_2 Fire Protection System, Cable Tray and Conduit Provisions for Performance Testing including Test Ports, Thermowells, Instrumentation and DCS interface cards
4.0	**INLET AND EXHAUST SYSTEMS**	Inlet Duct Trash Screens, Inlet Duct and Silencers, Self Cleaning Filters, Hoist System For Filter Maintenance, Evaporative Cooler System, Exhaust Duct Expansion Joint, Exhaust Silencers Inlet and Exhaust Flow, Pressure and Temperature Ports and Instrumentation
5.0	**FUEL SYSTEMS**	

	System	System Scope
5.1	Fuel Syngas System	Gas Valves Including Vent, Throttle and Trip Valves Gas Filter/Separator Gas Supply Instruments and Instrument Panel
5.2	Backup Fuel System	Specific to backup fuel type
6.0	**STARTING SYSTEM**	Enclosure, Starting Motor or Static Start System, Turning Gear and Clutch Assembly, Starting Clutch Torque Converter
7.0	**GENERATOR**	Static or Rotating Exciter (Excitation transformer to be included for a static system), Line Termination Enclosure with CTs, VTs, Surge Arrestors, and Surge Capacitors, Neutral Cubicle with CT, Neutral Tie Bus, Grounding Transformer, and Secondary Resistor, Generator Gas Dryer, Seal Oil System (including Defoaming Tank, Reservoir, Seal Oil Pump, Emergency Seal Oil Pump, Vapor Extractor, and Oil Mist Eliminator), Generator Auxiliaries Control Enclosure, Generator Breaker, Iso-Phase bus connecting generator and breaker, Grounding System Connectors
7.1	Generator Cooling	TEWAC System (including circulation system, interconnecting piping and controls), or Hydrogen Cooling System (including H_2 to Glycol and Glycol to Air heat exchangers, liquid level detector circulation system, interconnecting piping and controls)
8.0	**Miscellaneous**	Interconnecting Pipe, Wire, Tubing and Cable, Instrument Air System Including Air Dryer, On Line and Off Line Water Wash System, LP CO_2 Storage Tank, Drain System, Drain Tanks, Coupling, Coupling Cover and Associated Hardware

CT Firing Temperature Control Issue for Low Calorific Value Fuel

A gas turbine when fired on low calorific value syngas has the potential to increase power output due to the increase in flow rate through the turbine. The higher turbine flow and moisture content of the combustion products can contribute to overheating of turbine components, affect rating criteria for the parts lives, and require a reduction in syngas firing temperatures (compared to the natural gas firing) to maintain design metal temperature. [44] Uncontrolled syngas firing temperature could result in more than 50 percent life cycle reduction of stage 1 buckets. Control systems for syngas applications include provisions to compensate for these effects by maintaining virtually constant generation output for the range of the specified ambient conditions. Inlet guide vanes (IGV) and firing temperature are used to maintain the turbine output at the maximum torque rating, producing a flat rating up to the IGV full open position. Beyond the IGV full open position, flat output may be extended to higher ambient air temperatures by steam/nitrogen injection.

In this study the firing temperature (defined as inlet rotor temperature) using natural gas in NGCC applications is 1399°C (2550°F) while the firing temperature in the non-capture IGCC cases is 1343-1354°C (2450-2470°F) and in the CO_2 capture cases is 1318-1327°C (2405-

2420°F). The further reduction in firing temperature in the CO_2 capture cases is done to maintain parts life as the H_2O content of the combustion products increases from 8-10 volume percent (vol%) in the non-capture cases to 14-16 vol% in the capture cases. The decrease in temperature also results in the lower temperature steam cycle in the CO_2 capture cases (538°C/538°C [1000°F/1000°F] versus 566°C/566°C [1050°F/1050°F] for non-capture cases).

Combustion Turbine Syngas Fuel Requirements.

Typical fuel specifications and contaminant levels for successful combustion turbine operation are provided in reference [45] and presented for F Class machines in Exhibit 3-12 and Exhibit 3-13. The vast majority of published CT performance information is specific to natural gas operation. Turbine performance using syngas requires vendor input as was obtained for this study.

Exhibit 3-12 Typical Fuel Specification for F-Class Machines

	Max	Min
LHV, kJ/m^3 (Btu/scf)	None	3.0 (100)
Gas Fuel Pressure, MPa (psia)	3.1 (450)	
Gas Fuel Temperature, °C (°F)	(1)	Varies with gas pressure (2)
Flammability Limit Ratio, Rich-to-Lean, Volume Basis	(3)	2:2.1
Sulfur	(4)	

Notes:

1. The maximum fuel temperature is defined in reference [46]
2. To ensure that the fuel gas supply to the gas turbine is 100 percent free of liquids the minimum fuel gas temperature must meet the required superheat over the respective dew point. This requirement is independent of the hydrocarbon and moisture concentration. Superheat calculation shall be performed as described in GEI-4140G [45].
3. Maximum flammability ratio limit is not defined. Fuel with flammability ratio significantly larger than those of natural gas may require start-up fuel
4. The quantity of sulfur in syngas is not limited by specification. Experience has shown that fuel sulfur levels up to 1 percent by volume do not significantly affect oxidation/corrosion rates.

Normal Operation

Inlet air is compressed in a single spool compressor to a pressure ratio of approximately 16:1. This pressure ratio was vendor specified and less than the 18.5:1 ratio used in natural gas applications. The majority of compressor discharge air remains on-board the machine and passes to the burner section to support combustion of the syngas. Compressed air is also used in burner, transition, and film cooling services. About 4-7 percent of the compressor air is extracted and integrated with the air supply of the ASU in non-carbon capture cases. It may be technically possible to integrate the CT and ASU in CO_2 capture cases as well; however, in this study integration was considered only for non-carbon capture cases.

Exhibit 3-13 Allowable Gas Fuel Contaminant Level for F-Class Machines

	Turbine Inlet Limit, ppbw	Fuel Limit, ppmw		
		Turbine Inlet Flow/Fuel Flow		
		50	*12*	*4*
Lead	20	1.0	0.240	.080
Vanadium	10	0.5	0.120	0.040
Calcium	40	2.0	0.480	0.160
Magnesium	40	2.0	0.480	0.160
Sodium + Potassium				
Na/K = 28 (1)	20	1.0	0.240	0.080
Na/K = 3	10	0.5	0.120	0.40
Na/K ≤ 1	6	0.3	0.072	0.024
Particulates Total (2)	600	30	7.2	2.4
Above 10 microns	6	0.3	0.072	0.024

Notes:
1. Na/K=28 is nominal sea salt ratio
2. The fuel gas delivery system shall be designed to prevent generation or admittance of solid particulate to the gas turbine gas fuel system

Pressurized syngas is combusted in several (14) parallel diffusion combustors and syngas dilution is used to limit NOx formation. As described in Section 3.1.2 nitrogen from the ASU is used as the primary diluent followed by syngas humidification and finally by steam dilution, if necessary, to achieve an LHV of 4.5-4.8 MJ/Nm^3 (120-128 Btu/scf). The advantages of using nitrogen as the primary diluent include:

- Nitrogen from the ASU is already partially compressed and using it for dilution eliminates wasting the compression energy.
- Limiting the water content reduces the need to de-rate firing temperature, particularly in the high-hydrogen (CO_2 capture) cases.

There are some disadvantages to using nitrogen as the primary diluent, and these include:

- There is a significant auxiliary power requirement to further compress the large nitrogen flow from the ASU pressures of 0.4 and 1.3 MPa (56 and 182 psia) to the CT pressure of 3.2 MPa (465 psia).

- The low quality heat used in the syngas humidification process does not provide significant benefit to the process in other applications.
- Nitrogen is not as efficient as water in limiting NOx emissions

It is not clear that one dilution method provides a significant advantage over the other. However, in this study nitrogen was chosen as the primary diluent based on suggestions by turbine industry experts during peer review of the report.

Hot combustion products are expanded in the three-stage turbine-expander. Given the assumed ambient conditions, back-end loss, and HRSG pressure drop, the CT exhaust temperature is nominally 599°C (1110°F) for non-CO2 capture cases and 566°C (1050°F) for capture cases.

Gross turbine power, as measured prior to the generator terminals, is 232 MW. The CT generator is a standard hydrogen-cooled machine with static exciter.

3.1.9 STEAM GENERATION ISLAND

Heat Recovery Steam Generator

The heat recovery steam generator (HRSG) is a horizontal gas flow, drum-type, multi-pressure design that is matched to the characteristics of the gas turbine exhaust gas when firing medium-Btu gas. High-temperature flue gas exiting the CT is conveyed through the HRSG to recover the large quantity of thermal energy that remains. Flue gas travels through the HRSG gas path and exits at 132°C (270°F) for all six IGCC cases.

The high pressure (HP) drum produces steam at main steam pressure, while the intermediate pressure (IP) drum produces process steam and turbine dilution steam, if required. The HRSG drum pressures are nominally 12.4/2.9 MPa (1800/420 psia) for the HP/IP turbine sections, respectively. In addition to generating and superheating steam, the HRSG performs reheat duty for the cold/hot reheat steam for the steam turbine, provides condensate and feedwater heating, and also provides deaeration of the condensate.

Natural circulation of steam is accomplished in the HRSG by utilizing differences in densities due to temperature differences of the steam. The natural circulation HRSG provides the most cost-effective and reliable design.

The HRSG drums include moisture separators, internal baffles, and piping for feedwater/steam. All tubes, including economizers, superheaters, and headers and drums, are equipped with drains.

Safety relief valves are furnished in order to comply with appropriate codes and ensure a safe work place.

Superheater, boiler, and economizer sections are supported by shop-assembled structural steel. Inlet and outlet duct is provided to route the gases from the gas turbine outlet to the HRSG inlet and the HRSG outlet to the stack. A diverter valve is included in the inlet duct to bypass the gas when appropriate. Suitable expansion joints are also included.

Steam Turbine Generator and Auxiliaries

The steam turbine consists of an HP section, an IP section, and one double-flow low pressure (LP) section, all connected to the generator by a common shaft. The HP and IP sections are contained in a single-span, opposed-flow casing, with the double-flow LP section in a separate casing. The LP turbine has a last stage bucket length of 76 cm (30 in).

Main steam from the HRSG and gasifier island is combined in a header, and then passes through the stop valves and control valves and enters the turbine at either 12.4 MPa/566°C (1800 psig/1050°F) for the non-carbon capture cases, or 12.4 MPa/538°C (1800 psig/1000°F) for the carbon capture cases. The steam initially enters the turbine near the middle of the high-pressure span, flows through the turbine, and returns to the HRSG for reheating. The reheat steam flows through the reheat stop valves and intercept valves and enters the IP section at 2.6 to 2.9 MPa/566°C (375 to 420 psig/1050°F) for the non-carbon capture cases or 2.6 to 2.9 MPa/538°C (375 to 420 psig/1000°F) for the carbon capture cases. After passing through the IP section, the steam enters a crossover pipe, which transports the steam to the LP section. The steam divides into two paths and flows through the LP sections, exhausting downward into the condenser.

Turbine bearings are lubricated by a closed-loop, water-cooled, pressurized oil system. The oil is contained in a reservoir located below the turbine floor. During startup or unit trip an emergency oil pump mounted on the reservoir pumps the oil. When the turbine reaches 95 percent of synchronous speed, the main pump mounted on the turbine shaft pumps oil. The oil flows through water-cooled heat exchangers prior to entering the bearings. The oil then flows through the bearings and returns by gravity to the lube oil reservoir.

Turbine shafts are sealed against air in-leakage or steam blowout using a modern positive pressure variable clearance shaft sealing design arrangement connected to a low-pressure steam seal system. During startup, seal steam is provided from the main steam line. As the unit increases load, HP turbine gland leakage provides the seal steam. Pressure-regulating valves control the gland header pressure and dump any excess steam to the condenser. A steam packing exhauster maintains a vacuum at the outer gland seals to prevent leakage of steam into the turbine room. Any steam collected is condensed in the packing exhauster and returned to the condensate system.

The generator is a hydrogen-cooled synchronous type, generating power at 24 kV. A static, transformer type exciter is provided. The generator is cooled with a hydrogen gas recirculation system using fans mounted on the generator rotor shaft. The heat absorbed by the gas is removed as it passes over finned tube gas coolers mounted in the stator frame. Gas is prevented from escaping at the rotor shafts by a closed-loop oil seal system. The oil seal system consists of storage tank, pumps, filters, and pressure controls, all skid-mounted.

The steam turbine generator is controlled by a triple-redundant, microprocessor-based electro-hydraulic control system. The system provides digital control of the unit in accordance with programmed control algorithms, color CRT operator interfacing, and datalink interfaces to the balance-of-plant DCS, and incorporates on-line repair capability.

Condensate System

The condensate system transfers condensate from the condenser hotwell to the deaerator, through the gland steam condenser, gasifier, and the low-temperature economizer section in the HRSG. The system consists of one main condenser; two 50 percent capacity, motor-driven, vertical condensate pumps; one gland steam condenser; and a low-temperature tube bundle in the HRSG. Condensate is delivered to a common discharge header through separate pump discharge lines, each with a check valve and a gate valve. A common minimum flow recirculation line discharging to the condenser is provided to maintain minimum flow requirements for the gland steam condenser and the condensate pumps.

Feedwater System

The function of the feedwater system is to pump the various feedwater streams from the deaerator storage tank in the HRSG to the respective steam drums. Two 50 percent capacity boiler feed pumps are provided for each of three pressure levels, HP, IP, and LP. Each pump is provided with inlet and outlet isolation valves, and outlet check valve. Minimum flow recirculation to prevent overheating and cavitation of the pumps during startup and low loads is provided by an automatic recirculation valve and associated piping that discharges back to the deaerator storage tank. Pneumatic flow control valves control the recirculation flow.

The feedwater pumps are supplied with instrumentation to monitor and alarm on low oil pressure, or high bearing temperature. Feedwater pump suction pressure and temperature are also monitored. In addition, the suction of each boiler feed pump is equipped with a startup strainer.

Main and Reheat Steam Systems

The function of the main steam system is to convey main steam generated in the synthesis gas cooler (SGC) and HRSG from the HRSG superheater outlet to the HP turbine stop valves. The function of the reheat system is to convey steam from the HP turbine exhaust to the HRSG reheater, and to the turbine reheat stop valves.

Main steam at approximately 12.4 MPa/566°C (1800 psig/1050°F) (non-carbon capture cases) or 12.4 MPa/538°C (1800 psig/1000°F) (carbon capture cases) exits the HRSG superheater through a motor-operated stop/check valve and a motor-operated gate valve, and is routed to the HP turbine. Cold reheat steam at approximately 3.1 to 3.4 MPa/341°C (450 to 500 psia/645°F) exits the HP turbine, flows through a motor-operated isolation gate valve, to the HRSG reheater. Hot reheat steam at approximately 2.9 to 3.2 MPa/566°C (420 to 467 psia/1050°F) for non-carbon capture cases and 2.9 MPa/538°C (420 psia/1000°F) for carbon capture cases exits the HRSG reheater through a motor-operated gate valve and is routed to the IP turbines.

Steam piping is sloped from the HRSG to the drip pots located near the steam turbine for removal of condensate from the steam lines. Condensate collected in the drip pots and in low-point drains is discharged to the condenser through the drain system.

Steam flow is measured by means of flow nozzles in the steam piping. The flow nozzles are located upstream of any branch connections on the main headers.

Safety valves are installed to comply with appropriate codes and to ensure the safety of personnel and equipment.

Circulating Water System

The circulating water system is a closed-cycle cooling water system that supplies cooling water to the condenser to condense the main turbine exhaust steam. The system also supplies cooling water to the AGR plant as required, and to the auxiliary cooling system. The auxiliary cooling system is a closed-loop process that utilizes a higher quality water to remove heat from compressor intercoolers, oil coolers and other ancillary equipment and transfers that heat to the main circulating cooling water system in plate and frame heat exchangers. The heat transferred to the circulating water in the condenser and other applications is removed by a mechanical draft cooling tower.

The system consists of two 50 percent capacity vertical circulating water pumps, a mechanical draft evaporative cooling tower, and carbon steel cement-lined interconnecting piping. The pumps are single-stage vertical pumps. The piping system is equipped with butterfly isolation valves and all required expansion joints. The cooling tower is a multi-cell wood frame counterflow mechanical draft cooling tower.

The condenser is a single-pass, horizontal type with divided water boxes. There are two separate circulating water circuits in each box. One-half of the condenser can be removed from service for cleaning or for plugging tubes. This can be done during normal operation at reduced load.

The condenser is equipped with an air extraction system to evacuate the condenser steam space for removal of non-condensable gases during steam turbine operation and to rapidly reduce the condenser pressure from atmospheric pressure before unit startup and admission of steam to the condenser.

Raw Water, Fire Protection, and Cycle Makeup Water Systems

The raw water system supplies cooling tower makeup, cycle makeup, service water and potable water requirements. The water source is 50 percent from a POTW and 50 percent from groundwater. Booster pumps within the plant boundary provide the necessary pressure.

The fire protection system provides water under pressure to the fire hydrants, hose stations, and fixed water suppression system within the buildings and structures. The system consists of pumps, underground and aboveground supply piping, distribution piping, hydrants, hose stations, spray systems, and deluge spray systems. One motor-operated booster pump is supplied on the intake structure of the cooling tower with a diesel engine backup pump installed on the water inlet line.

The cycle makeup water system provides high quality demineralized water for makeup to the HRSG cycle, for steam injection ahead of the water gas shift reactors in CO_2 capture cases, and for injection steam to the auxiliary boiler for control of NOx emissions, if required.

The cycle makeup system consists of two 100 percent trains, each with a full-capacity activated carbon filter, primary cation exchanger, primary anion exchanger, mixed bed exchanger, recycle pump, and regeneration equipment. The equipment is skid-mounted and includes a control panel and associated piping, valves, and instrumentation.

3.1.10 Accessory Electric Plant

The accessory electric plant consists of switchgear and control equipment, generator equipment, station service equipment, conduit and cable trays, and wire and cable. It also includes the main power transformer, all required foundations, and standby equipment.

3.1.11 Instrumentation and Control

An integrated plant-wide distributed control system (DCS) is provided. The DCS is a redundant microprocessor-based, functionally distributed control system. The control room houses an array of multiple video monitor (CRT) and keyboard units. The CRT/keyboard units are the primary interface between the generating process and operations personnel. The DCS incorporates plant monitoring and control functions for all the major plant equipment. The DCS is designed to be operational and accessible 99.5 percent of the time it is required (99.5 percent availability). The plant equipment and the DCS are designed for automatic response to load changes from minimum load to 100 percent. Startup and shutdown routines are manually implemented, with operator selection of modular automation routines available. The exception to this, and an important facet of the control system for gasification, is the critical controller system, which is a part of the license package from the gasifier supplier and is a dedicated and distinct hardware segment of the DCS.

This critical controller system is used to control the gasification process. The partial oxidation of the fuel feed and oxygen feed streams to form a syngas product is a stoichiometric, temperature- and pressure-dependent reaction. The critical controller utilizes a redundant microprocessor executing calculations and dynamic controls at 100- to 200-millisecond intervals. The enhanced execution speeds as well as evolved predictive controls allow the critical controller to mitigate process upsets and maintain the reactor operation within a stable set of operating parameters.

3.2 GENERAL ELECTRIC ENERGY IGCC CASES

This section contains an evaluation of plant designs for Cases 1 and 2, which are based on the GEE gasifier in the "radiant only" configuration. GEE offers three design configurations [47]:

- Quench: In this configuration, the hot syngas exiting the gasifier passes through a pool of water to quench the temperature to less than 260°C (500°F) before entering the syngas scrubber. It is the simplest and lowest capital cost design, but also the least efficient.
- Radiant Only: In this configuration, the hot syngas exiting the gasifier passes through a radiant syngas cooler where it is cooled from about 1316°C (2400°F) to 816°C (1500°F), then through a water quench where the syngas is further cooled to about 204°C (400°F) prior to entering the syngas scrubber. Relative to the quench configuration, the radiant only design offers increased output, higher efficiency, improved reliability/availability, and results in the lowest cost of electricity. This configuration was chosen by GEE and Bechtel for the design of their reference plant.
- Radiant-Convective: In this configuration, the hot syngas exiting the gasifier passes through a radiant syngas cooler where it is cooled from about 1316°C (2400°F) to 760°C (1400°F), then passes over a pool of water where particulate is removed but the syngas is not quenched, then through a convective syngas cooler where the syngas is further cooled to about 371°C (700°F) prior to entering additional heat exchangers or the scrubber. This configuration has the highest overall efficiency, but at the expense of highest capital cost and the lowest availability. This is the configuration used at Tampa Electric's Polk Power Station.

Note that the radiant only configuration includes a water quench and, based on functionality, would be more appropriately named radiant-quench. The term radiant only is used to distinguish it from the radiant-convective configuration. Since radiant only is the terminology used by GEE, it will be used throughout this report.

The balance of Section 3.2 is organized as follows:

- Gasifier Background provides information on the development and status of the GEE gasification technology.
- Process and System Description provides an overview of the technology operation as applied to Case 1. The systems that are common to all gasifiers were covered in Section 3.1 and only features that are unique to Case 1 are discussed further in this section.
- Key Assumptions is a summary of study and modeling assumptions relevant to Cases 1 and 2.
- Sparing Philosophy is provided for both Cases 1 and 2.
- Performance Results provides the main modeling results from Case 1, including the performance summary, environmental performance, carbon balance, sulfur balance, water balance, mass and energy balance diagrams and mass and energy balance tables.
- Equipment List provides an itemized list of major equipment for Case 1 with account codes that correspond to the cost accounts in the Cost Estimates section.
- Cost Estimates provides a summary of capital and operating costs for Case 1.

- Process and System Description, Performance Results, Equipment List and Cost Estimates are repeated for Case 2.

3.2.1 GASIFIER BACKGROUND

Development and Current Status [48] **–** Initial development of the GEE gasification technology (formerly licensed by Texaco and then ChevronTexaco) was conducted in the 1940s at Texaco's Montebello, California laboratories. From 1946 to 1954 the Montebello pilot plant produced synthesis gas (hydrogen and carbon monoxide) by partial oxidation of a variety of feedstocks, including natural gas, oil, asphalt, coal tar, and coal. From 1956 to 1958, coal was gasified in a 91 tonne/day (100 TPD) Texaco coal gasifier at the Olin Mathieson Chemical Plant in Morgantown, West Virginia, for the production of ammonia.

The oil price increases and supply disruptions of the 1970s renewed interest in the Texaco partial-oxidation process for gasification of coal or other solid opportunity fuels. Three 14 tonne/day (15 TPD) pilot plants at the Montebello laboratories have been used to test numerous coals. Two larger pilot plants were also built. The first gasified 150 tonne/day (165 TPD) of coal and was built to test synthesis gas generation by Rührchemie and Rührkohle at Oberhausen, Germany, and included a synthesis gas cooler. The second gasified 172 tonne/day (190 TPD) of coal using a quench-only gasifier cooler and was built to make hydrogen at an existing TVA ammonia plant at Muscle Shoals, Alabama. These two large-scale pilot plants successfully operated for several years during the 1980s and tested a number of process variables and numerous coals.

The first commercial Texaco coal gasification plant was built for Tennessee Eastman at Kingsport, Tennessee, and started up in 1983. To date, 24 gasifiers have been built in 12 plants for coal and petroleum coke. Several of the plants require a hydrogen-rich gas and therefore directly water quench the raw gas to add the water for shifting the CO to H_2, and have no synthesis gas coolers.

The Cool Water plant was the first commercial-scale Texaco coal gasification project for the electric utility industry. This facility gasified 907 tonne/day (1,000 TPD) (dry basis) of bituminous coal and generated 120 MW of electricity by IGCC operation. In addition, the plant was the first commercial-sized Texaco gasifier used with a synthesis gas cooler. The Cool Water plant operated from 1984 to 1989 and was a success in terms of operability, availability, and environmental performance.

The Tampa Electric IGCC Clean Coal Technology Demonstration Project built on the Cool Water experience to demonstrate the use of the Texaco coal gasification process in an IGCC plant. The plant utilizes approximately 2,268 tonne/day (2,500 TPD) of coal in a single Texaco gasifier to generate a net of approximately 250 MW_e. The syngas is cooled in a high-temperature radiant heat exchanger, generating high-pressure steam, and further cooled in convective heat exchangers (the radiant-convective configuration). The particles in the cooled gas are removed in a water-based scrubber. The cleaned gas then enters a hydrolysis reactor where COS is converted to H_2S. After additional cooling, the syngas is sent to a conventional AGR unit, where H_2S is absorbed by reaction with an amine solvent. H_2S is removed from the amine by steam stripping and sent to a sulfuric acid plant. The cleaned gas is sent to a General Electric MS 7001FA combustion turbine.

The Delaware Clean Energy Project is a coke gasification and combustion turbine repowering of an existing 130 MW coke-fired boiler cogeneration power plant at the Motiva oil refinery in Delaware City, Delaware. The Texaco coal gasification process was modified to gasify 1,814 tonne/day (2,000 TPD) of this low-quality petroleum coke. The plant is designed to use all the fluid petroleum coke generated at Motiva's Delaware City Plant and produce a nominal 238,136 kg/h (525,000 lb/h) of 8.6 MPa (1250 psig) steam, and 120,656 kg/h (266,000 lb/h) of 1.2 MPa (175 psig) steam for export to the refinery and the use/sale of 120 MW of electrical power. Environmentally, these new facilities help satisfy tighter NO_x and SO_2 emission limitations at the Delaware City Plant.

Gasifier Capacity – The largest GEE gasifier is the unit at Tampa Electric, which consists of the radiant-convective configuration. The daily coal-handling capacity of this unit is 2,268 tonnes (2,500 tons) of bituminous coal. The dry gas production rate is 0.19 million Nm^3/h (6.7 million scfh) with an energy content of about 1,897 million kJ/h (HHV) (1,800 million Btu/h). This size matches the F Class combustion turbines that are used at Tampa.

Distinguishing Characteristics – A key advantage of the GEE coal gasification technology is the extensive operating experience at full commercial scale. Furthermore, Tampa Electric is an IGCC power generation facility, operated by conventional electric utility staff, and is environmentally one of the cleanest coal-fired power plants in the world. The GEE gasifier also operates at the highest pressure of the three gasifiers in this study, 5.6 MPa (815 psia) compared to 4.2 MPa (615 psia) for CoP and Shell.

Entrained-flow gasifiers have fundamental environmental advantages over fluidized-bed and moving-bed gasifiers. They produce no hydrocarbon liquids, and the only solid waste is an inert slag. The relatively high H_2/CO ratio and CO_2 content of GEE gasification fuel gas helps achieve low nitrogen oxide (NO_x) and CO emissions in even the higher-temperature advanced combustion turbines.

The key disadvantages of the GEE coal gasification technology are the limited refractory life, the relatively high oxygen requirements and high waste heat recovery duty (synthesis gas cooler design). As with the other entrained-flow slagging gasifiers, the GEE process has this disadvantage due to its high operating temperature. The disadvantage is magnified in the single-stage, slurry feed design. The quench design significantly reduces the capital cost of syngas cooling, while innovative heat integration maintains good overall thermal efficiency although lower than the synthesis gas cooler design. Another disadvantage of the GEE process is the limited ability to economically handle low-rank coals relative to moving-bed and fluidized-bed gasifiers or to entrained-flow gasifiers with dry feed. For slurry fed entrained gasifiers using low-rank coals, developers of two-stage slurry fed gasifiers claim advantages over single-stage slurry fed.

Important Coal Characteristics – The slurry feeding system and the recycle of process condensate water as the principal slurrying liquid make low levels of ash and soluble salts desirable coal characteristics for use in the GEE coal gasification process. High ash levels increase the ratio of water-to-carbon in the feed slurry, thereby increasing the oxygen requirements. The slurry feeding also favors the use of high-rank coals, such as bituminous coal, since their low inherent moisture content increases the moisture-free solids content of the slurry and thereby reduces oxygen requirements.

3.2.2 PROCESS DESCRIPTION

In this section the overall GEE gasification process is described. The system description follows the block flow diagram (BFD) in Exhibit 3-14 and stream numbers reference the same Exhibit. The tables in Exhibit 3-15 provide stream compositions, temperature, pressure, enthalpy and flow rates for the numbered streams in the BFD.

Coal Grinding and Slurry Preparation

Coal receiving and handling is common to all cases and was covered in Section 3.1.1. The receiving and handling subsystem ends at the coal silo. Coal is then fed onto a conveyor by vibratory feeders located below each silo. The conveyor feeds the coal to an inclined conveyor that delivers the coal to the rod mill feed hopper. The feed hopper provides a surge capacity of about two hours and contains two hopper outlets. Each hopper outlet discharges onto a weigh feeder, which in turn feeds a rod mill. Each rod mill is sized to process 55 percent of the coal feed requirements of the gasifier. The rod mill grinds the coal and wets it with treated slurry water transferred from the slurry water tank by the slurry water pumps. The coal slurry is discharged through a trommel screen into the rod mill discharge tank, and then the slurry is pumped to the slurry storage tanks. The dry solids concentration of the final slurry is 63 percent. The Polk Power Station operates at a slurry concentration of 62-68 percent using bituminous coal and CoP presented a paper showing the slurry concentration of Illinois No. 6 coal as 63 percent. [41, 49]

The coal grinding system is equipped with a dust suppression system consisting of water sprays aided by a wetting agent. The degree of dust suppression required depends on local environmental regulations. All of the tanks are equipped with vertical agitators to keep the coal slurry solids suspended.

The equipment in the coal grinding and slurry preparation system is fabricated of materials appropriate for the abrasive environment present in the system. The tanks and agitators are rubber lined. The pumps are either rubber-lined or hardened metal to minimize erosion. Piping is fabricated of high-density polyethylene (HDPE).

Gasification

This plant utilizes two gasification trains to process a total of 5,331 tonnes/day (5,876 TPD) of Illinois No. 6 coal. Each of the 2 x 50 percent gasifiers operates at maximum capacity. The largest operating GEE gasifier is the 2,268 tonne/day (2,500 TPD) unit at Polk Power Station. However, that unit operates at about 2.8 MPa (400 psia). The gasifier in this study, which operates at 5.6 MPa (815 psia), will be able to process more coal and maintain the same gas residence time.

The slurry feed pump takes suction from the slurry run tank, and the discharge is sent to the feed injector of the GEE gasifier (stream 6). Oxygen from the ASU is vented during preparation for startup and is sent to the feed injector during normal operation. The air separation plant supplies 4,560 tonnes/day (5,025 TPD) of 95 mole percent oxygen to the gasifiers (stream 5) and the Claus plant (stream 3). Carbon conversion in the gasifier is assumed to be 98 percent including a fines recycle stream.

The gasifier vessel is a refractory-lined, high-pressure combustion chamber. The coal slurry feedstock and oxygen are fed through a fuel injector at the top of the gasifier vessel. The coal slurry and the oxygen react in the gasifier at 5.6 MPa (815 psia) and 1,316°C (2,400°F) to produce syngas.

The syngas consists primarily of hydrogen and carbon monoxide, with lesser amounts of water vapor and carbon dioxide, and small amounts of hydrogen sulfide, carbonyl sulfide, methane, argon, and nitrogen. The heat in the gasifier liquefies coal ash. Hot syngas and molten solids from the reactor flow downward into a radiant heat exchanger where the syngas is cooled.

Raw Gas Cooling/Particulate Removal

Syngas is cooled from 1,316°C (2,400°F) to 593°C (1,100°F) in the radiant synthesis gas cooler (SGC) (stream 8) and the molten slag solidifies in the process. The solids collect in the water sump at the bottom of the gasifier and are removed periodically using a lock hopper system (stream 7). The waste heat from this cooling is used to generate high-pressure steam. Boiler feedwater in the tubes is saturated, and then steam and water are separated in a steam drum. Approximately 528,118 kg/h (1,164,300 lb/h) of saturated steam at 13.8 MPa (2,000 psia) is produced. This steam then forms part of the general heat recovery system that provides steam to the steam turbine.

The syngas exiting the radiant cooler is directed downwards by a dip tube into a water sump. Most of the entrained solids are separated from the syngas at the bottom of the dip tube as the syngas goes upwards through the water. The syngas exits the quench chamber saturated at a temperature of 210°C (410°F).

The slag handling system removes solids from the gasification process equipment. These solids consist of a small amount of unconverted carbon and essentially all of the ash contained in the feed coal. These solids are in the form of glass, which fully encapsulates any metals. Solids collected in the water sump below the radiant synthesis gas cooler are removed by gravity and forced circulation of water from the lock hopper circulating pump. The fine solids not removed from the bottom of the quench water sump remain entrained in the water circulating through the quench chamber. In order to limit the amount of solids recycled to the quench chamber, a continuous blowdown stream is removed from the bottom of the syngas quench. The blowdown is sent to the vacuum flash drum in the black water flash section. The circulating quench water is pumped by circulating pumps to the quench gasifier.

Syngas Scrubber/Sour Water Stripper

Syngas exiting the water quench passes to a syngas scrubber where a water wash is used to remove remaining chlorides and particulate. The syngas exits the scrubber still saturated at 199°C (390°F) (stream 9).

The sour water stripper removes NH_3, SO_2, and other impurities from the scrubber and other waste streams. The stripper consists of a sour drum that accumulates sour water from the gas scrubber and condensate from synthesis gas coolers. Sour water from the drum flows to the sour stripper, which consists of a packed column with a steam-heated reboiler. Sour gas is stripped from the liquid and sent to the sulfur recovery unit. Remaining water is sent to wastewater treatment.

Exhibit 3-14 Case 1 Process Flow Diagram, GEE IGCC without CO_2 Capture

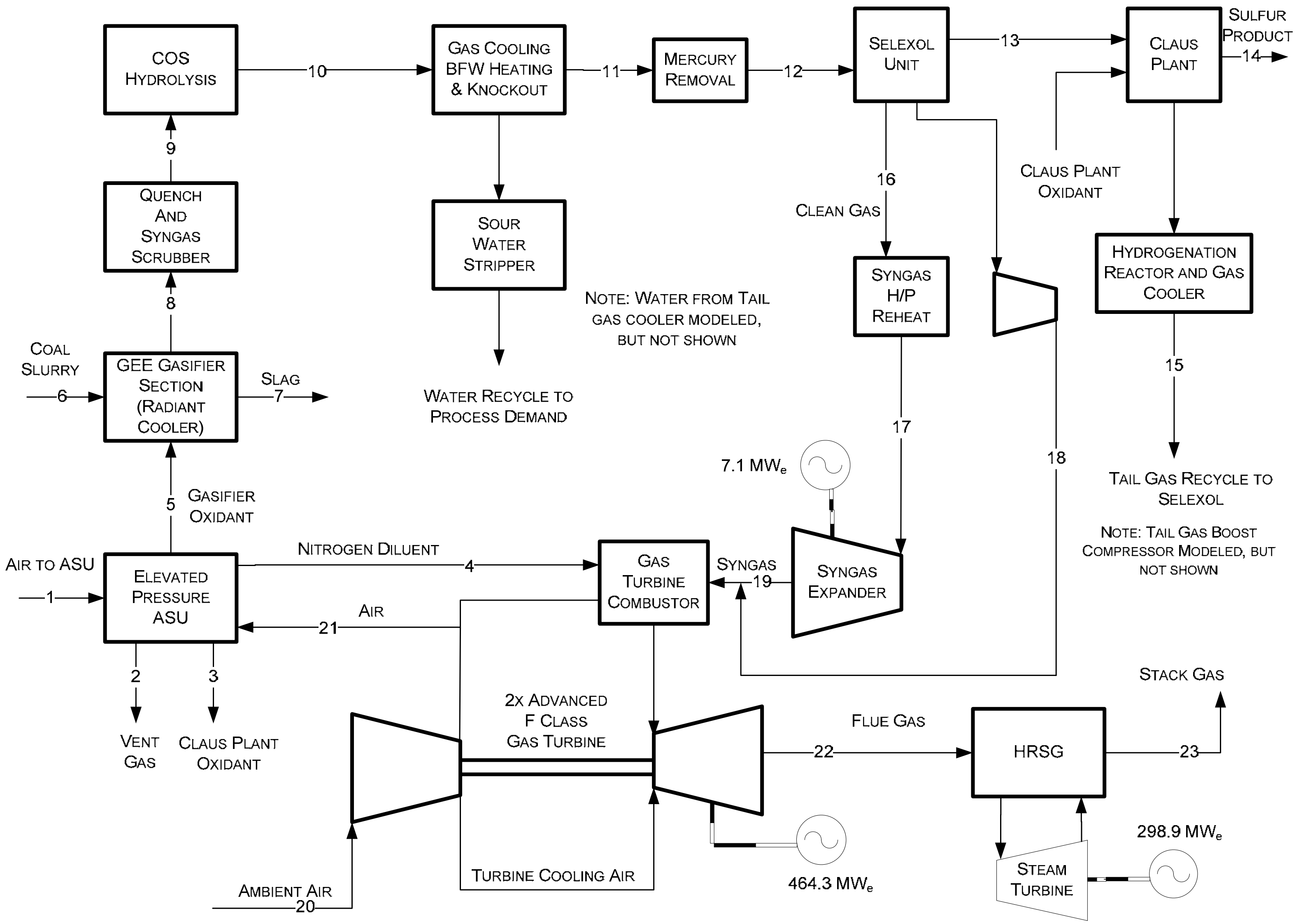


Exhibit 3-15 Case 1 Stream Table, GEE IGCC without CO_2 Capture

	1	2	3	4	5	6[A]	7	8	9	10	11	12
V-L Mole Fraction												
Ar	0.0094	0.0065	0.0360	0.0023	0.0320	0.0000	0.0000	0.0079	0.0067	0.0067	0.0092	0.0092
CH_4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0010	0.0008	0.0008	0.0011	0.0011
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3442	0.2922	0.2922	0.3992	0.3992
CO_2	0.0003	0.0015	0.0000	0.0000	0.0000	0.0000	0.0000	0.1511	0.1276	0.1278	0.1780	0.1780
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0002	0.0002	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3349	0.2849	0.2849	0.3935	0.3935
H_2O	0.0104	0.0496	0.0000	0.0000	0.0000	1.0000	0.0000	0.1429	0.2726	0.2724	0.0012	0.0012
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0073	0.0061	0.0062	0.0069	0.0069
N_2	0.7722	0.8978	0.0140	0.9924	0.0180	0.0000	0.0000	0.0089	0.0076	0.0076	0.0103	0.0103
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0017	0.0014	0.0014	0.0006	0.0006
O_2	0.2077	0.0445	0.9500	0.0053	0.9500	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	53,342	13,347	277	36,897	12,736	14,199	0	51,296	60,278	60,278	43,585	43,585
V-L Flowrate (lb/hr)	1,539,150	371,000	8,942	1,035,410	409,853	255,589	0	1,046,880	1,206,760	1,206,760	904,411	904,411
Solids Flowrate (lb/hr)	0	0	0	0	0	435,187	53,746	0	0	0	0	0
Temperature (°F)	233	58	90	385	206	141	410	1100	390	390	107	107
Pressure (psia)	190.1	16.4	125.0	460.0	980.0	1050.0	797.7	799.7	792.7	782.7	742.7	732.7
Enthalpy (BTU/lb)[B]	55.6	16.6	12.5	87.8	37.7	---	1,710	535.5	400.3	400.3	27.4	27.4
Density (lb/ft^3)	0.738	0.085	0.683	1.424	4.416	---	---	0.975	1.740	1.718	2.534	2.500
Molecular Weight	28.85	27.80	32.23	28.06	32.18	---	---	20.41	20.02	20.02	20.75	20.75

A - Solids flowrate includes dry coal; V-L flowrate includes slurry water and water from coal

B - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 3-15 Case 1 Stream Table (continued)

	13	14	15	16	17	18	19	20	21	22	23
V-L Mole Fraction											
Ar	0.0000	0.0000	0.0188	0.0097	0.0097	0.0059	0.0097	0.0094	0.0094	0.0091	0.0091
CH_4	0.0000	0.0000	0.0764	0.0012	0.0012	0.0169	0.0012	0.0000	0.0000	0.0000	0.0000
CO	0.0000	0.0000	0.0003	0.4195	0.4195	0.0814	0.4195	0.0000	0.0000	0.0000	0.0000
CO_2	0.3803	0.0000	0.6066	0.1414	0.1414	0.5518	0.1414	0.0003	0.0003	0.0859	0.0859
COS	0.0002	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0126	0.4164	0.4164	0.0532	0.4164	0.0000	0.0000	0.0000	0.0000
H_2O	0.0200	0.0000	0.0020	0.0009	0.0009	0.0000	0.0009	0.0104	0.0104	0.0668	0.0668
H_2S	0.3576	0.0000	0.0103	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.2106	0.0000	0.2728	0.0110	0.0110	0.2908	0.0110	0.7722	0.7722	0.7337	0.7337
NH_3	0.0313	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2077	0.2077	0.1045	0.1045
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	0	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	863	0	860	40,704	40,704	3,978	40,704	242,899	9,914	297,284	297,284
V-L Flowrate (lb/hr)	30,839	0	31,584	795,458	795,458	140,512	795,458	7,008,680	286,060	8,694,000	8,694,000
Solids Flowrate (lb/hr)	0	12,235	0	0	0	0	0	0	0	0	0
Temperature (°F)	120	358	100	112	460	151	380	59	811	1115	270
Pressure (psia)	30.0	24.9	368.0	719.0	714.0	460.0	460.0	14.7	234.9	15.2	15.2
Enthalpy (BTU/lb)[B]	31.1	-99.5	16.1	30.3	162.2	27.1	131.2	13.5	200.0	327.2	103.2
Density (lb/ft^3)	0.172	329.192	2.252	2.289	1.414	2.481	0.998	0.076	0.497	0.026	0.057
Molecular Weight	35.73	256.53	36.74	19.54	19.54	35.33	19.54	28.85	28.85	29.24	29.24

B - Reference conditions are 32.02 F & 0.089 PSIA

COS Hydryolysis, Mercury Removal and Acid Gas Removal

Syngas exiting the scrubber (stream 9) passes through a COS hydrolysis reactor where about 99.5 percent of the COS is converted to CO_2 and H_2S (Section 3.1.5). The gas exiting the COS reactor (stream 10) passes through a series of heat exchangers and knockout drums to lower the syngas temperature to 39°C (103°F) and to separate entrained water. The cooled syngas (stream 11) then passes through a carbon bed to remove 95 percent of the Hg (Section 3.1.4).

Cool, particulate-free synthesis gas (stream 12) enters the Selexol absorber unit at approximately 5.1 MPa (733 psia) and 39°C (103°F). In this absorber, H_2S is preferentially removed from the fuel gas stream along with smaller amounts of CO_2, COS and other gases such as hydrogen. The rich solution leaving the bottom of the absorber is heated against the lean solvent returning from the regenerator before entering the H_2S concentrator. A portion of the non-sulfur bearing absorbed gases is driven from the solvent in the H_2S concentrator using N_2 from the ASU as the stripping medium. The temperature of the H_2S concentrator overhead stream is reduced prior to entering the reabsorber where a second stage of H_2S absorption occurs. The rich solvent from the reabsorber is combined with the rich solvent from the absorber and sent to the stripper where it is regenerated through the indirect application of thermal energy via condensation of low-pressure steam in a reboiler. The stripper acid gas stream (stream 13), consisting of 36 percent H_2S and 38 percent CO_2 (with the balance mostly N_2), is then sent to the Claus unit. The secondary sweet fuel gas stream from the reabsorber is compressed to 3.2 MPa (460 psia) (stream 18) and combined with the primary sweet syngas after the expansion turbine (stream 19).

Claus Unit

Acid gas from the first-stage stripper of the Selexol unit is routed to the Claus plant. The Claus plant partially oxidizes the H_2S in the acid gas to elemental sulfur. About 5,550 kg/h (12,235 lb/h) of elemental sulfur (stream 14) are recovered from the fuel gas stream. This value represents an overall sulfur recovery efficiency of 99.6 percent.

Acid gas from the Selexol unit is preheated to 232°C (450°F). A portion of the acid gas along with all of the sour gas from the stripper and oxygen from the ASU are fed to the Claus furnace. In the furnace, H_2S is catalytically oxidized to SO_2 at a furnace temperature greater than 1,343°C (2,450°F), which must be maintained in order to thermally decompose all of the NH_3 present in the sour gas stream.

Following the thermal stage and condensation of sulfur, two reheaters and two sulfur converters are used to obtain a per-pass H_2S conversion of approximately 99.7 percent. The Claus Plant tail gas is hydrogenated and recycled back to the Selexol process (stream 15). In the furnace waste heat boiler, 8,772 kg/h (19,340 lb/h) of 3.6 MPa (525 psia) steam are generated. This steam is used to satisfy all Claus process preheating and reheating requirements as well as to produce some steam for the medium-pressure steam header. The sulfur condensers produce 0.34 MPa (50 psig) steam for the low-pressure steam header.

Power Block

Clean syngas exiting the Selexol absorber is re-heated (stream 17) using HP boiler feedwater and then expanded to 3.2 MPa (460 psia) using an expansion turbine (stream 19). A second clean gas stream from the Selexol reabsorber is compressed and combined with stream 19. The combined syngas stream is further diluted with nitrogen from the ASU (stream 4) and enters the advanced F Class CT burner. The CT compressor provides combustion air to the burner and also 16 percent of the air requirements in the ASU (stream 21). The exhaust gas exits the CT at 602°C (1,115°F) (stream 22) and enters the HRSG where additional heat is recovered until the flue gas exits the HRSG at 132°C (270°F) (stream 23) and is discharged through the plant stack. The steam raised in the HRSG is used to power an advanced, commercially available steam turbine using a 12.4 MPa/566°C/566°C (1800 psig/1050°F/1050°F) steam cycle.

Air Separation Unit (ASU)

The elevated pressure ASU was described in Section 3.1.2. In Case 1 the air separation unit (ASU) is designed to produce a nominal output of 4,560 tonnes/day (5,025 TPD) of 95 mole percent O_2 for use in the gasifier (stream 5) and Claus plant (stream 3). The plant is designed with two production trains. The air compressor is powered by an electric motor. Approximately 11,270 tonnes/day (12,425 TPD) of nitrogen are also recovered, compressed, and used as dilution in the gas turbine combustor (stream 4). About 4.1 percent of the gas turbine air is used to supply approximately 16 percent of the ASU air requirements (stream 21).

Balance of Plant

Balance of plant items were covered in Sections 3.1.9, 3.1.10 and 3.1.11.

3.2.3 KEY SYSTEM ASSUMPTIONS

System assumptions for Cases 1 and 2, GEE IGCC with and without CO_2 capture, are presented in Exhibit 3-16.

Exhibit 3-16 GEE IGCC Plant Study Configuration Matrix

Case	1	2
Gasifier Pressure, MPa (psia)	5.6 (815)	5.6 (815)
O_2:Coal Ratio, kg O_2/kg dry coal	0.95	0.95
Carbon Conversion, %	98	98
Syngas HHV at SGC Outlet, kJ/Nm^3 (Btu/scf)	8,210 (226)	8,210 (226)
Steam Cycle, MPa/°C/°C (psig/°F/°F)	12.4/566/566 (1800/1050/1050)	12.4/538/538 (1800/1000/1000)
Condenser Pressure, mm Hg (in Hg)	51 (2.0)	51 (2.0)
Combustion Turbine	2x Advanced F Class (232 MW output each)	2x Advanced F Class (232 MW output each)
Gasifier Technology	GEE Radiant Only	GEE Radiant Only
Oxidant	95 vol% Oxygen	95 vol% Oxygen
Coal	Illinois No. 6	Illinois No. 6
Coal Slurry Solids Conent, %	63	63
COS Hydrolysis	Yes	Occurs in SGS
Sour Gas Shift	No	Yes
H_2S Separation	Selexol	Selexol 1st Stage
Sulfur Removal, %	99.6	99.6
Sulfur Recovery	Claus Plant with Tail Gas Recycle to Selexol/ Elemental Sulfur	Claus Plant with Tail Gas Recycle to Selexol/ Elemental Sulfur
Particulate Control	Water Quench, Scrubber, and AGR Absorber	Water Quench, Scrubber, and AGR Absorber
Mercury Control	Carbon Bed	Carbon Bed
NOx Control	MNQC (LNB) and N_2 Dilution	MNQC (LNB) and N_2 Dilution
CO_2 Separation	N/A	Selexol 2nd Stage
CO_2 Capture	N/A	90.2% from Syngas
CO_2 Sequestration	N/A	Off-site Saline Formation

Balance of Plant – Cases 1 and 2

The balance of plant assumptions are common to all cases and are presented in Exhibit 3-17.

Exhibit 3-17 Balance of Plant Assumptions

Cooling system	Recirculating Wet Cooling Tower
Fuel and Other storage	
Coal	30 days
Slag	30 days
Sulfur	30 days
Sorbent	30 days
Plant Distribution Voltage	
Motors below 1 hp	110/220 volt
Motors between 1 hp and 250 hp	480 volt
Motors between 250 hp and 5,000 hp	4,160 volt
Motors above 5,000 hp	13,800 volt
Steam and Gas Turbine Generators	24,000 volt
Grid Interconnection Voltage	345 kV
Water and Waste Water	
Makeup Water	The water supply is 50 percent from a local Publicly Owned Treatment Works and 50 percent from groundwater, and is assumed to be in sufficient quantities to meet plant makeup requirements. Makeup for potable, process, and de-ionized (DI) water is drawn from municipal sources
Process Wastewater	Water associated with gasification activity and storm water that contacts equipment surfaces is collected and treated for discharge through a permitted discharge.
Sanitary Waste Disposal	Design includes a packaged domestic sewage treatment plant with effluent discharged to the industrial wastewater treatment system. Sludge is hauled off site. Packaged plant was sized for 5.68 cubic meters per day (1,500 gallons per day)
Water Discharge	Most of the process wastewater is recycled to the cooling tower basin. Blowdown is treated for chloride and metals, and discharged.

3.2.4 SPARING PHILOSOPHY

The sparing philosophy for Cases 1 and 2 is provided below. Single trains are utilized throughout with exceptions where equipment capacity requires an additional train. There is no redundancy other than normal sparing of rotating equipment.

The plant design consists of the following major subsystems:

- Two air separation units (2 x 50%)
- Two trains of slurry preparation and slurry pumps (2 x 50%)
- Two trains of gasification, including gasifier, synthesis gas cooler, quench and scrubber (2 x 50%).
- Two trains of syngas clean-up process (2 x 50%).
- Two trains of Selexol acid gas removal, single-stage in Case 1 and two-stage in Case 2, (2 x 50%) and one Claus-based sulfur recovery unit (1 x 100%).
- Two combustion turbine/HRSG tandems (2 x 50%).
- One steam turbine (1 x 100%).

3.2.5 CASE 1 PERFORMANCE RESULTS

The plant produces a net output of 640 MWe at a net plant efficiency of 38.2 percent (HHV basis). GEE has reported a net plant effiency of 38.5 percent for their reference plant, and they also presented a range of efficiencies of 38.5-40 percent depending on fuel type. [50, 51] Typically the higher efficiencies result from fuel blends that include petroleum coke.

Overall performance for the plant is summarized in Exhibit 3-18 which includes auxiliary power requirements. The ASU accounts for over 79 percent of the auxiliary load between the main air compressor, the nitrogen compressor, the oxygen compressor and ASU auxiliaries. The cooling water system, including the circulating water pumps and the cooling tower fan, accounts for over 4 percent of the auxiliary load, and the BFW pumps account for an additional 3.5 percent. All other individual auxiliary loads are less than 3 percent of the total.

Exhibit 3-18 Case 1 Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine Power	464,300
Sweet Gas Expander Power	7,130
Steam Turbine Power	298,920
TOTAL POWER, kWe	**770,350**
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	450
Coal Milling	2,280
Coal Slurry Pumps	740
Slag Handling and Dewatering	1,170
Air Separation Unit Auxiliaries	1,000
Air Separation Unit Main Air Compressor	60,070
Oxygen Compressor	11,270
Nitrogen Compressor	30,560
Claus Plant Tail Gas Recycle Compressor	1,230
Boiler Feedwater Pumps	4,590
Condensate Pump	250
Flash Bottoms Pump	200
Circulating Water Pumps	3,710
Cooling Tower Fans	1,910
Scrubber Pumps	300
Selexol Unit Auxiliaries	3,420
Gas Turbine Auxiliaries	1,000
Steam Turbine Auxiliaries	100
Claus Plant/TGTU Auxiliaries	200
Miscellaneous Balance of Plant (Note 1)	3,000
Transformer Loss	2,650
TOTAL AUXILIARIES, kWe	**130,100**
NET POWER, kWe	**640,250**
Net Plant Efficiency, % (HHV)	38.2
Net Plant Heat Rate (Btu/kWh)	8,922
CONDENSER COOLING DUTY 10^6 kJ/h (10^6 Btu/h)	**1,705 (1,617)**
CONSUMABLES	
As-Received Coal Feed, kg/h (lb/h)	222,095 (489,634)
Thermal Input, kWt	1,674,044
Raw Water Usage, m^3/min (gpm)	15.2 (4,003)

Note 1: Includes plant control systems, lighting, HVAC and miscellaneous low voltage loads

Environmental Performance

The environmental targets for emissions of Hg, NOx, SO_2 and particulate matter were presented in Section 2.4. A summary of the plant air emissions for Case 1 is presented in Exhibit 3-19.

Exhibit 3-19 Case 1 Air Emissions

	kg/GJ ($lb/10^6$ Btu)	Tonne/year (ton/year) @ 80% capacity factor	kg/MWh (lb/MWh)
SO_2	0.005 (0.0127)	231 (254)	0.043 (0.094)
NO_X	0.024 (0.055)	994 (1,096)	0.184 (0.406)
Particulates	0.003 (0.0071)	129 (142)	0.024 (0.053)
Hg	$0.25x10^{-6}$ ($.57x10^{-6}$)	0.010 (0.011)	$1.9x10^{-6}$ ($4.2x10^{-6}$)
CO_2	85 (197)	3,572,000 (3,938,000)	662 (1,459)
CO_2[1]			796 (1,755)

[1] CO_2 emissions based on net power instead of gross power

The low level of SO_2 emissions is achieved by capture of the sulfur in the gas by the Selexol AGR process. The AGR process removes over 99 percent of the sulfur compounds in the fuel gas down to a level of less than 30 ppmv. This results in a concentration in the flue gas of less than 4 ppmv. The H_2S-rich regeneration gas from the AGR system is fed to a Claus plant, producing elemental sulfur. The Claus plant tail gas is hydrogenated to convert all sulfur species to H_2S and then recycled back to the Selexol process, thereby eliminating the need for a tail gas treatment unit.

NO_X emissions are limited by nitrogen dilution of the syngas to 15 ppmvd (as NO_2 @15 percent O_2). Ammonia in the syngas is removed with process condensate prior to the low-temperature AGR process and ultimately destroyed in the Claus plant burner. This helps lower NO_X levels as well.

Particulate discharge to the atmosphere is limited to extremely low values by the use of the syngas quench in addition to the syngas scrubber and the gas washing effect of the AGR absorber. The particulate emissions represent filterable particulate only.

Ninety five percent of the mercury is captured from the syngas by an activated carbon bed. CO_2 emissions represent the uncontrolled discharge from the process.

The carbon balance for the plant is shown in Exhibit 3-20. The carbon input to the plant consists of carbon in the air in addition to carbon in the coal. Carbon in the air is not neglected here since the AspenPlus model accounts for air components throughout. Carbon leaves the plant as unburned carbon in the slag, as dissolved CO_2 in the wastewater blowdown stream, and as CO_2 in the stack gas and ASU vent gas. Carbon in the wastewater blowdown stream is calculated by difference to close the material balance.

Exhibit 3-20 Case 1 Carbon Balance

Carbon In, kg/hr (lb/hr)		Carbon Out, kg/hr (lb/hr)	
Coal	141,585 (312,142)	**Slag**	2,843 (6,267)
Air (CO_2)	529 (1,165)	**Stack Gas**	139,020 (306,486)
		ASU Vent	111 (245)
		Wastewater	141 (310)
Total	142,114 (313,307)	**Total**	142,114 (313,307)

Exhibit 3-21 shows the sulfur balances for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered in the Claus plant, dissolved SO_2 in the wastewater blowdown stream, and sulfur emitted in the stack gas. Sulfur in the slag is considered to be negligible, and the sulfur content of the blowdown stream is calculated by difference to close the material balance. The total sulfur capture is represented by the following fraction:

(Sulfur byproduct/Sulfur in the coal) or
(12,235/12,290) or
99.6 percent

Exhibit 3-21 Case 1 Sulfur Balance

Sulfur In, kg/hr (lb/hr)		Sulfur Out, kg/hr (lb/hr)	
Coal	5,575 (12,290)	**Elemental Sulfur**	5,550 (12,235)
		Stack Gas	16 (36)
		Wastewater	8 (19)
Total	5,575 (12,290)	**Total**	5,575 (12,290)

Exhibit 3-22 shows the overall water balance for the plant. Raw water is obtained from groundwater (50 percent) and from municipal sources (50 percent). Water demand represents the total amount of water required for a particular process. Some water is recovered within the process, primarily as syngas condensate, and that water is re-used as internal recycle. Raw water makeup is the difference between water demand and internal recycle.

Exhibit 3-22 Case 1 Water Balance

Water Use	Water Demand, m^3/min (gpm)	Internal Recycle, m^3/min (gpm)	Raw Water Makeup, m^3/min (gpm)
Slurry	1.5 (402)	1.5 (402)	0
Slag Handling	0.5 (140)	0	0.5 (140)
Quench/Scrubber	2.1 (561)	1.6 (427)	0.5 (134)
BFW Makeup	0.2 (49)	0	0.2 (49)
Cooling Tower Makeup	14.4 (3,805)	0.5 (125)	13.9 (3,680)
Total	**18.7 (4,957)**	**3.6 (954)**	**15.2 (4,003)**

Heat and Mass Balance Diagrams

Heat and mass balance diagrams are shown for the following subsystems in Exhibit 3-23 through Exhibit 3-27:

- Coal gasification and air separation unit
- Syngas cleanup
- Sulfur recovery and tail gas recycle
- Combined cycle power generation
- Steam and feedwater

An overall plant energy balance is provided in tabular form in Exhibit 3-28. The power out is the combined combustion turbine, steam turbine and expander power prior to generator losses. The power at the generator terminals (shown in Exhibit 3-18) is calculated by multiplying the power out by a combined generator efficiency of 98.2 percent.

The heat and material balances shown in these figures are shown in U.S. standard units. The following factors can be used for conversion to SI units. The same conversions apply to all cases but are shown only once for Case 1.

P, absolute pressure, psia, multiply by 6.895 x10^{-3} = MPa (megapascals)
°F, temperature, (°F minus 32) divided by 1.8 = °C (Centigrade)
H, enthalpy, Btu/lb, multiply H by 2.3260 = kJ/kg (kilojoules/kilogram)
W, total plant flow, lb/h, multiply W by 0.4536 = kg/h (kilogram/hour)
Heat rate, Btu/kWh, multiply Btu/kWh by 1.0551 = kJ/kWh (kilojoules/kilowatt-hour)

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Exhibit 3-23 Case 1 Coal Gasification and Air Separation Units Heat and Mass Balance Schematic

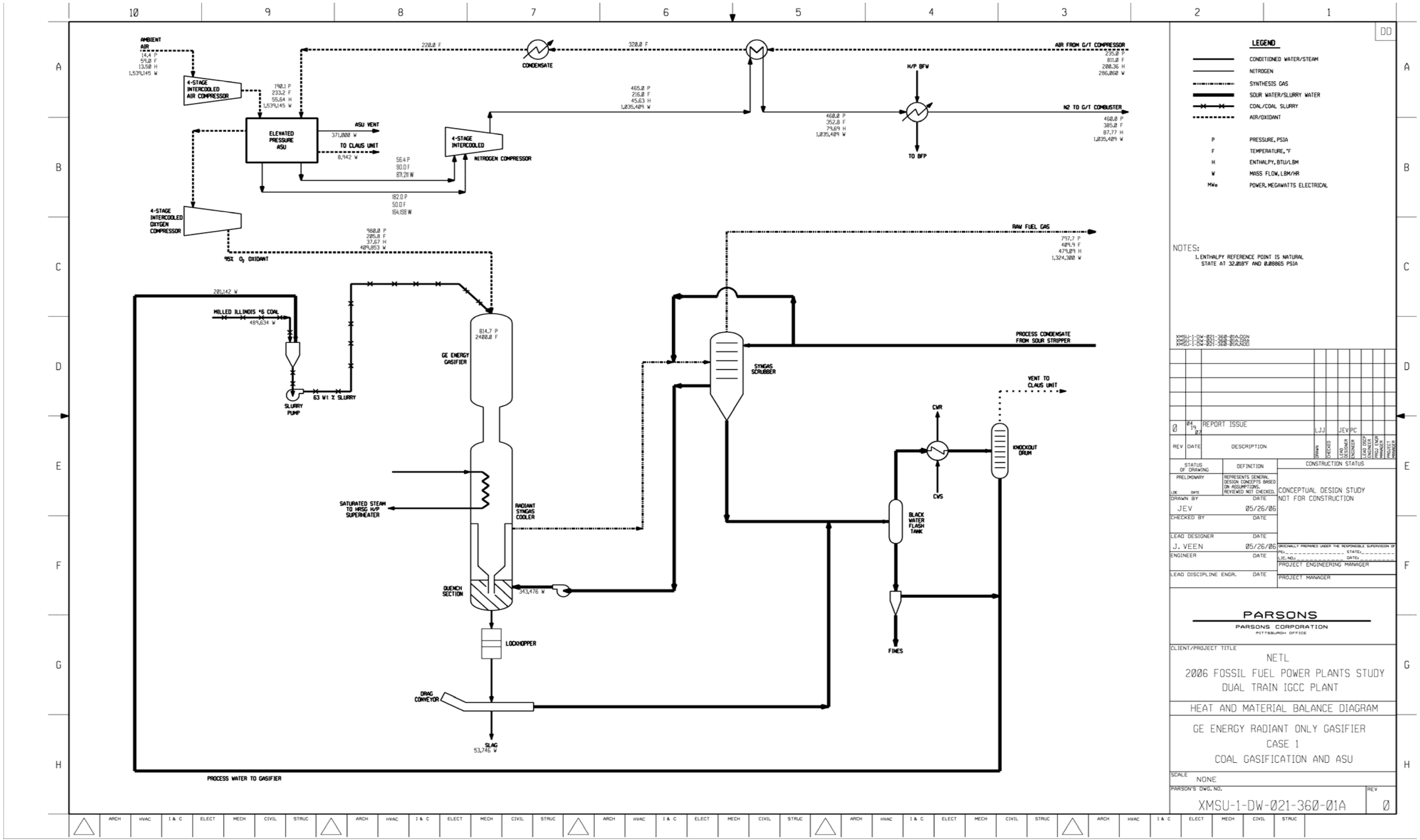

Exhibit 3-24 Case 1 Syngas Cleanup Heat and Mass Balance Schematic

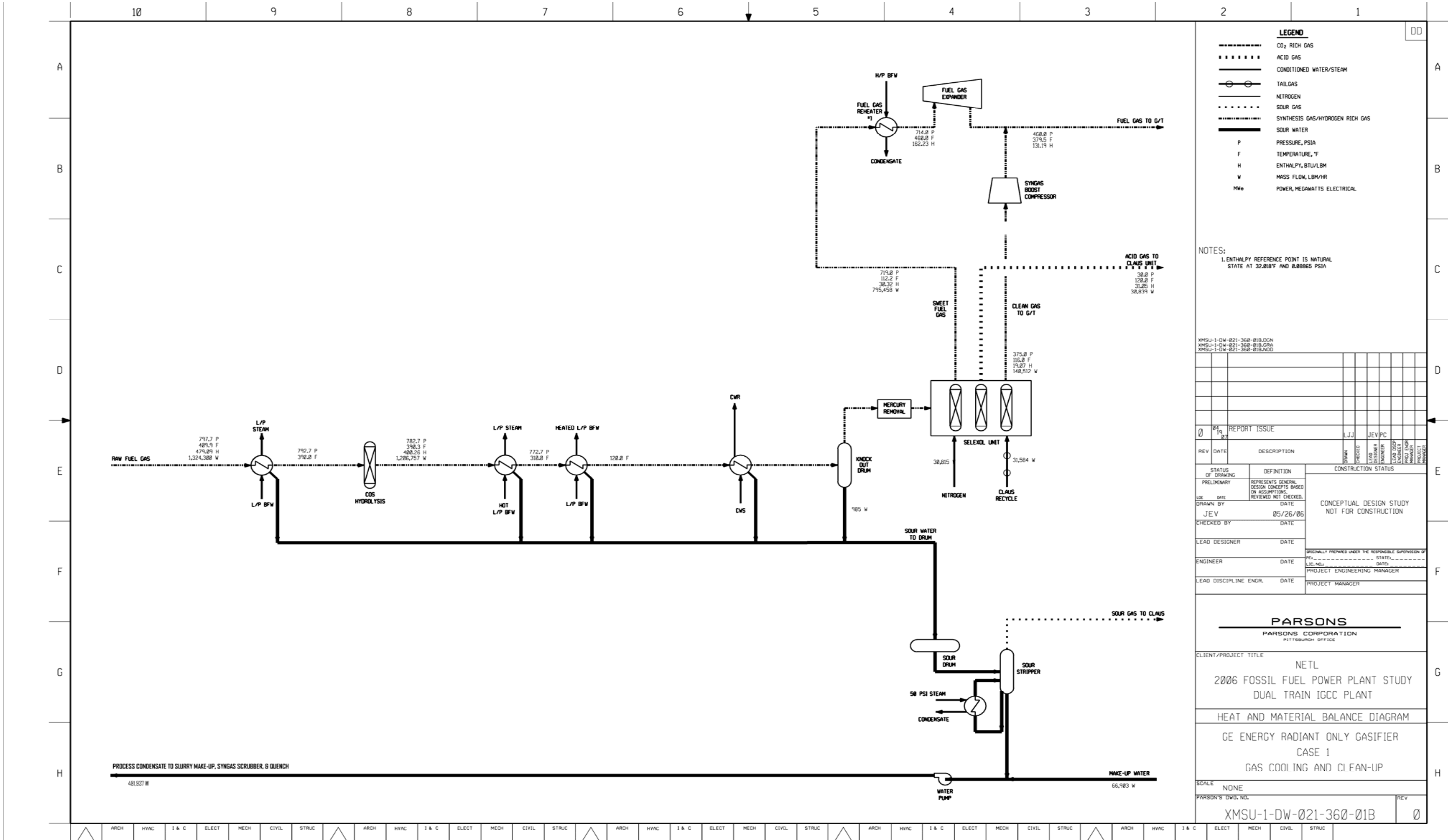

Exhibit 3-25 Case 1 Sulfur Recovery and Tail Gas Recycle Heat and Mass Balance Schematic

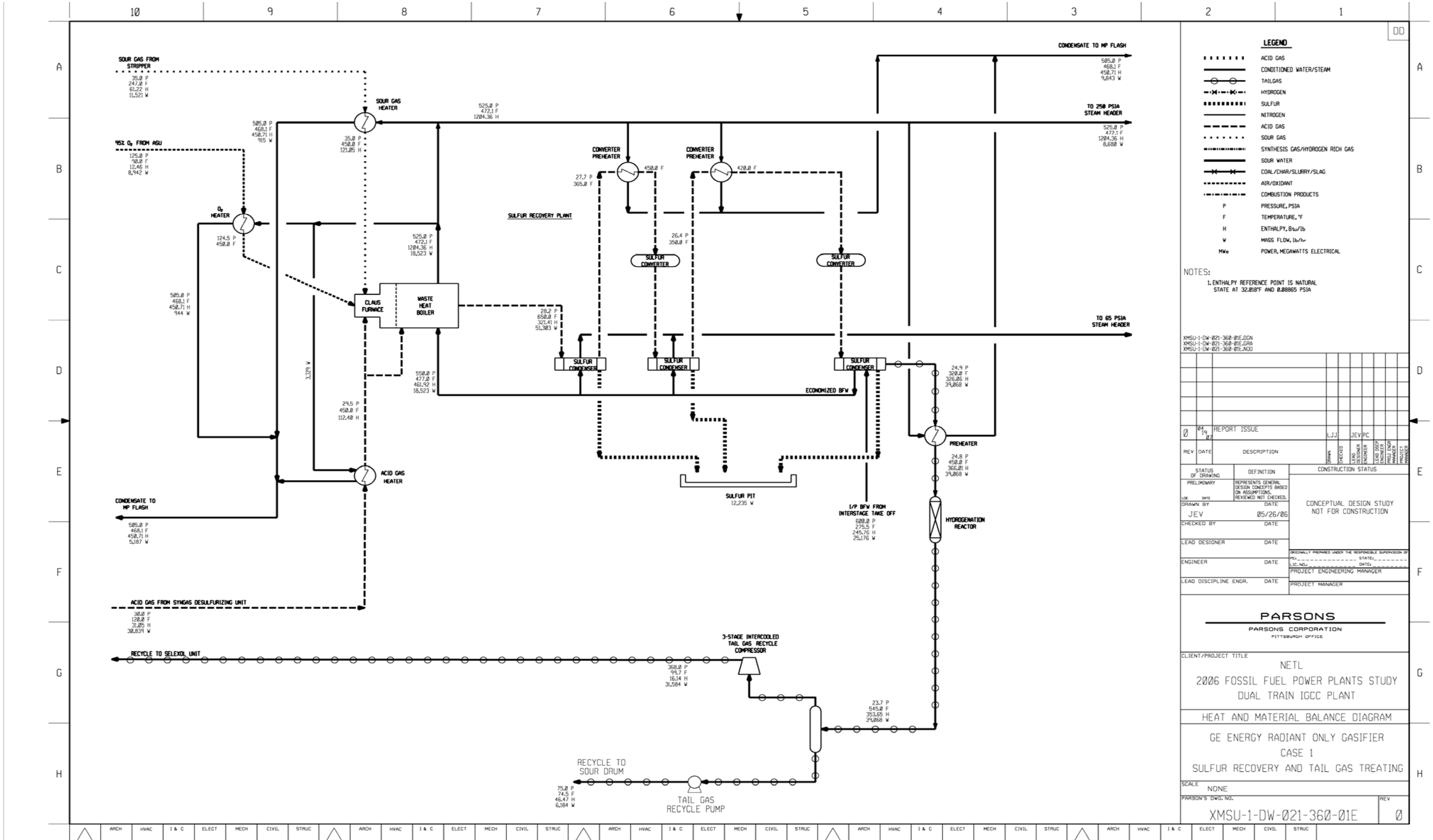

Exhibit 3-26 Case 1 Combined-Cycle Power Generation Heat and Mass Balance Schematic

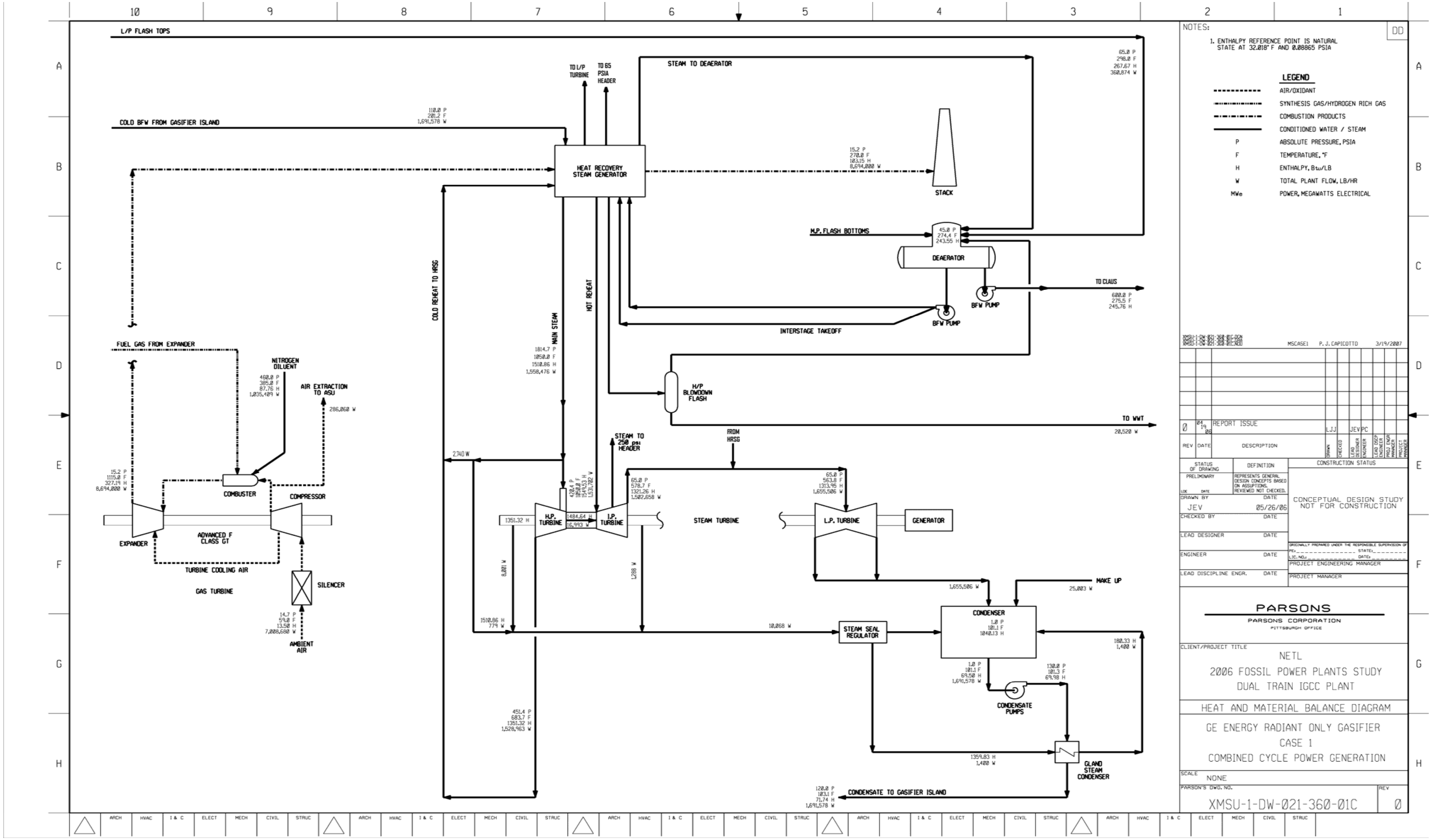

Exhibit 3-27 Case 1 Steam and Feedwater Heat and Mass Balance Schematic

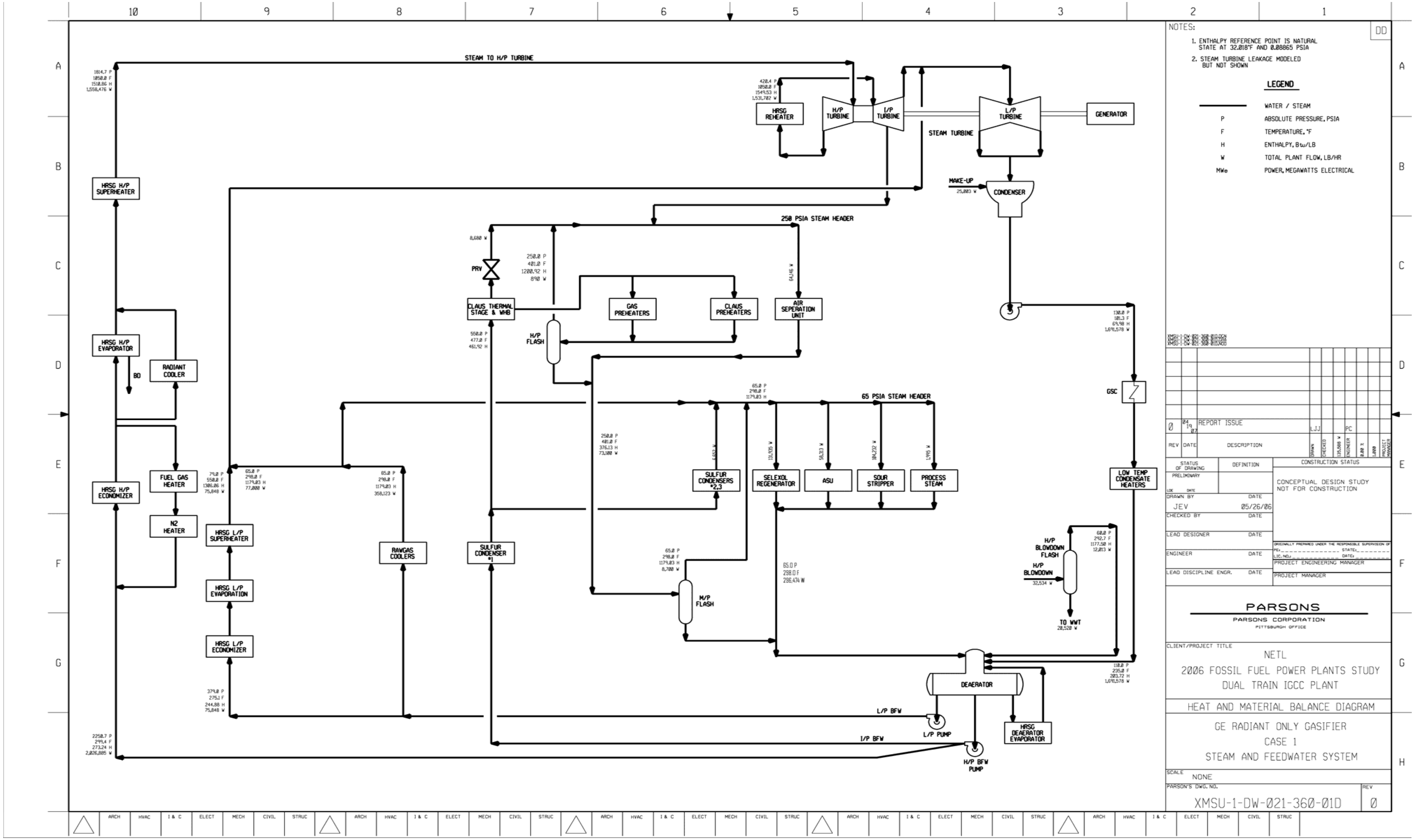

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Exhibit 3-28 Case 1 Overall Energy Balance (0°C [32°F] Reference)

	HHV	Sensible + Latent	Power	Total
Heat In (MMBtu/hr)				
Coal	5,712.1	4.8		5,716.8
ASU Air		20.8		20.8
CT Air		94.6		94.6
Water		2.9		2.9
Auxiliary Power			444.0	444.0
Totals	**5,712.1**	**123.1**	**444.0**	**6,279.2**
Heat Out (MMBtu/hr)				
ASU Intercoolers		228.0		228.0
ASU Vent		6.1		6.1
Slag	88.3	3.6		91.9
Sulfur	48.7	(1.2)		47.5
Tail Gas Compressor Intercoolers		4.4		4.4
HRSG Flue Gas		896.8		896.8
Condenser		1,617.0		1,617.0
Process Losses (1)		710.8		710.8
Power			2,676.7	2,676.7
Totals	**137.0**	**3,465.5**	**2,676.7**	**6,279.2**

(1) Process Losses are calculated by difference and reflect various gasification, turbine, HRSG and other heat and work losses. Aspen flowsheet balance is within 0.5 percent.

3.2.6 CASE 1 - MAJOR EQUIPMENT LIST

Major equipment items for the GEE gasifier with no CO_2 capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 3.2.7. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

ACCOUNT 1 COAL HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	181 tonne (200 ton)	2	0
2	Feeder	Belt	572 tonne/h (630 tph)	2	0
3	Conveyor No. 1	Belt	1,134 tonne/h (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,134 tonne/h (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,134 tonne/h (1,250 tph)	1	0
8	Reclaim Hopper	N/A	45 tonne (50 ton)	2	1
9	Feeder	Vibratory	181 tonne/h (200 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	363 tonne/h (400 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	181 tonne (200 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3" x 0 - 1-1/4" x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	363 tonne/h (400 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	363 tonne/h (400 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	816 tonne (900 ton)	3	0

ACCOUNT 2 COAL PREPARATION AND FEED

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Feeder	Gravimetric	82 tonne/h (90 tph)	3	0
2	Conveyor No. 6	Belt w/tripper	245 tonne/h (270 tph)	1	0
3	Rod Mill Feed Hopper	Dual Outlet	490 tonne (540 ton)	1	0
4	Weigh Feeder	Belt	118 tonne/h (130 tph)	2	0
5	Rod Mill	Rotary	118 tonne/h (130 tph)	2	0
6	Slurry Water Storage Tank with Agitator	Field erected	302,835 liters (80,000 gal)	2	0
7	Slurry Water Pumps	Centrifugal	833 lpm (220 gpm)	2	2
10	Trommel Screen	Coarse	172 tonne/h (190 tph)	2	0
11	Rod Mill Discharge Tank with Agitator	Field erected	320,248 liters (84,600 gal)	2	0
12	Rod Mill Product Pumps	Centrifugal	2,650 lpm (700 gpm)	2	2
13	Slurry Storage Tank with Agitator	Field erected	946,361 liters (250,000 gal)	2	0
14	Slurry Recycle Pumps	Centrifugal	5,337 lpm (1,410 gpm)	2	2
15	Slurry Product Pumps	Positive displacement	2,650 lpm (700 gpm)	2	2

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	745,732 liters (197,000 gal)	2	0
2	Condensate Pumps	Vertical canned	7,079 lpm @ 110 m H2O (1,870 gpm @ 360 ft H2O)	2	1
3	Deaerator (integral w/ HRSG)	Horizontal spray type	514,828 kg/h (1,135,000 lb/h)	2	0
4	Intermediate Pressure Feedwater Pump	Horizontal centrifugal, single stage	1,931 lpm @ 283 m H2O (510 gpm @ 930 ft H2O)	2	1
5	High Pressure Feedwater Pump No. 1	Barrel type, multi-stage, centrifugal	HP water: 6,890 lpm @ 1,890 m H2O (1,820 gpm @ 6,200 ft H2O)	2	1
6	High Pressure Feedwater Pump No. 2	Barrel type, multi-stage, centrifugal	IP water: 1,893 lpm @ 223 m H2O (500 gpm @ 730 ft H2O)	2	1
7	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/h, 2.8 MPa, 343°C (40,000 lb/h, 400 psig, 650°F)	1	0
8	Service Air Compressors	Flooded Screw	28 m3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
9	Instrument Air Dryers	Duplex, regenerative	28 m3/min (1,000 scfm)	2	1
10	Closed Cycle Cooling Heat Exchangers	Plate and frame	58 MMkJ/h (55 MMBtu/h) each	2	0
11	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,820 lpm @ 21 m H2O (5,500 gpm @ 70 ft H2O)	2	1
12	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H2O (1,000 gpm @ 290 ft H2O)	1	1
13	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H2O (700 gpm @ 210 ft H2O)	1	1
14	Raw Water Pumps	Stainless steel, single suction	8,593 lpm @ 18 m H2O (2,270 gpm @ 60 ft H2O)	2	1
15	Filtered Water Pumps	Stainless steel, single suction	2,498 lpm @ 49 m H2O (660 gpm @ 160 ft H2O)	2	1
16	Filtered Water Tank	Vertical, cylindrical	1,211,341 liter (320,000 gal)	2	0
17	Makeup Water Demineralizer	Anion, cation, and mixed bed	189 lpm (50 gpm)	2	0
18	Liquid Waste Treatment System		10 years, 24-hour storm	1	0

ACCOUNT 4 GASIFIER, ASU AND ACCESSORIES INCLUDING LOW TEMPERATURE HEAT RECOVERY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gasifier	Pressurized slurry-feed, entrained bed	2,903 tonne/day, 5.6 MPa (3,200 tpd, 815 psia)	2	0
2	Synthesis Gas Cooler	Vertical downflow radiant heat exchanger with outlet quench chamber	274,424 kg/h (605,000 lb/h)	2	0
3	Syngas Scrubber Including Sour Water Stripper	Vertical upflow	330,216 kg/h (728,000 lb/h)	2	0
4	Raw Gas Coolers	Shell and tube with condensate drain	301,186 kg/h (664,000 lb/h)	6	0
5	Raw Gas Knockout Drum	Vertical with mist eliminator	218,178 kg/h, 39°C, 5.2 MPa (481,000 lb/h, 103°F, 753 psia)	2	0
6	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	330,216 kg/h (728,000 lb/h) syngas	2	0
7	ASU Main Air Compressor	Centrifugal, multi-stage	5,267 m3/min @ 1.3 MPa (186,000 scfm @ 190 psia)	2	0
8	Cold Box	Vendor design	2,540 tonne/day (2,800 tpd) of 95% purity oxygen	2	0
9	Oxygen Compressor	Centrifugal, multi-stage	1,246 m3/min @ 7.1 MPa (44,000 scfm @ 1,030 psia)	2	0
10	Nitrogen Compressor	Centrifugal, multi-stage	3,058 m3/min @ 3.4 MPa (108,000 scfm @ 490 psia)	2	0
11	Nitrogen Boost Compressor	Centrifugal, multi-stage	566 m3/min @ 2.3 MPa (20,000 scfm @ 340 psia)	2	0
12	Extraction Air Heat Exchanger	Gas-to-gas, vendor design	71,214 kg/h, 433°C, 1.6 MPa (157,000 lb/h, 811°F, 235 psia)	2	0

ACCOUNT 5A SYNGAS CLEANUP

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Mercury Adsorber	Sulfated carbon bed	225,436 kg/h (497,000 lb/h) 42°C (107°F) 5.1 MPa (743 psia)	2	0
2	Sulfur Plant	Claus type	147 tonne/day (162 tpd)	1	0
3	COS Hydrolysis Reactor	Fixed bed, catalytic	301,186 kg/h (664,000 lb/h) 199°C (390°F) 5.5 MPa (793 psia)	2	0
4	Acid Gas Removal Plant	Selexol	225,436 kg/h (497,000 lb/h) 42°C (107°F) 5.1 MPa (733 psia)	2	0
5	Hydrogenation Reactor	Fixed bed, catalytic	19,504 kg/h (43,000 lb/h) 232°C (450°F) 0.2 MPa (25 psia)	1	0
6	Tail Gas Recycle Compressor	Centrifugal	183 m3/min @ 3.0 MPa (6,480 scfm @ 430 psia)	1	1

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gas Turbine	Advanced F class	232 MW	2	0
2	Gas Turbine Generator	TEWAC	260 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	2	0
3	Sweet Syngas Expansion Turbine/Generator	Turbo expander	198,447 kg/h (437,500 lb/h) Delta P: 2.1 MPa (310 psi) Power output: 3,980 kW	2	0

ACCOUNT 7 HRSG, DUCTING, AND STACK

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	CS plate, type 409SS liner	76 m (250 ft) high x 8.3 m (27 ft) diameter	1	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	Main steam - 388,803 kg/h, 12.4 MPa/566°C (857,162 lb/h, 1,800 psig/1,050°F) Reheat steam - 382,124 kg/h, 2.9 MPa/566°C (842,437 lb/h, 420 psig/1,050°F)	2	0

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	315 MW 12.4 MPa/566°C/566°C (1800 psig/ 1050°F/1050°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitiation	350 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Steam Bypass	One per HRSG	50% steam flow @ design steam conditions	2	0
4	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,876 MMkJ/h (1,780 MMBtu/h) heat duty, Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1	0

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	370,973 lpm @ 30 m (98,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT 2,066 MMkJ/h (1,960 MMBtu/h) heat load	1	0

ACCOUNT 10 SLAG RECOVERY AND HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Slag Quench Tank	Water bath	257,410 liters (68,000 gal)	2	0
2	Slag Crusher	Roll	14 tonne/h (15 tph)	2	0
3	Slag Depressurizer	Lock Hopper	14 tonne/h (15 tph)	2	0
4	Slag Receiving Tank	Horizontal, weir	166,559 liters (44,000 gal)	2	0
5	Black Water Overflow Tank	Shop fabricated	79,494 liters (21,000 gal)	2	0
6	Slag Conveyor	Drag chain	14 tonne/h (15 tph)	2	0
7	Slag Separation Screen	Vibrating	14 tonne/h (15 tph)	2	0
8	Coarse Slag Conveyor	Belt/bucket	14 tonne/h (15 tph)	2	0
9	Fine Ash Settling Tank	Vertical, gravity	249,839 liters (66,000 gal)	2	0
10	Fine Ash Recycle Pumps	Horizontal centrifugal	76 lpm @ 14 m H2O (20 gpm @ 46 ft H2O)	2	2
11	Grey Water Storage Tank	Field erected	79,494 liters (21,000 gal)	2	0
12	Grey Water Pumps	Centrifugal	303 lpm @ 564 m H2O (80 gpm @ 1,850 ft H2O)	2	2
13	Slag Storage Bin	Vertical, field erected	998 tonne (1,100 tons)	2	0
14	Unloading Equipment	Telescoping chute	109 tonne/h (120 tph)	1	0

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	24 kV/345 kV, 260 MVA, 3-ph, 60 Hz	2	0
2	STG Transformer	Oil-filled	24 kV/345 kV, 200 MVA, 3-ph, 60 Hz	1	0
3	Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 142 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 21 MVA, 3-ph, 60 Hz	1	1
5	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	2	0
6	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
7	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
8	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
9	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

ACCOUNT 12 INSTRUMENTATION AND CONTROLS

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

3.2.7 CASE 1 - COST ESTIMATING

The cost estimating methodology was described previously in Section 2.6. Exhibit 3-29 shows the total plant capital cost summary organized by cost account and Exhibit 3-30 shows a more detailed breakdown of the capital costs. Exhibit 3-31 shows the initial and annual O&M costs.

The estimated TPC of the GEE gasifier with no CO_2 capture is $1,813/kW. Process contingency represents 2.5 percent of the TPC and project contingency represents 13.3 percent. The 20-year LCOE is 78.0 mills/kWh

Exhibit 3-29 Case 1 Total Plant Cost Summary

Client: USDOE/NETL
Report Date: 05-Apr-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 01 - GEE Radiant Only IGCC w/o CO2
Plant Size: 640.3 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct		Equipment	Material	Labor		Sales	Bare Erected	Eng'g CM	Contingencies		TOTAL PLANT COST	
No.	Item/Description	Cost	Cost	Direct	Indirect	Tax	Cost $	H.O.& Fee	Process	Project	$	$/kW
1	COAL & SORBENT HANDLING	$13,505	$2,518	$10,582	$0	$0	**$26,606**	$2,410	$0	$5,803	**$34,819**	$54
2	COAL & SORBENT PREP & FEED	$23,112	$4,213	$13,999	$0	$0	**$41,324**	$3,748	$1,500	$9,315	**$55,887**	$87
3	FEEDWATER & MISC. BOP SYSTEMS	$9,975	$8,740	$9,353	$0	$0	**$28,067**	$2,620	$0	$6,893	**$37,580**	$59
4	GASIFIER & ACCESSORIES											
4.1	Syngas Cooler Gasifier System	$101,906	$0	$56,569	$0	$0	**$158,475**	$14,508	$21,881	$29,920	**$224,784**	$351
4.2	Syngas Cooler(w/ Gasifier - 4.1)	w/4.1	$0	w/4.1	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.3	ASU/Oxidant Compression	$152,787	$0	w/equip.	$0	$0	**$152,787**	$14,542	$0	$16,733	**$184,063**	$287
4.4-4.9	Other Gasification Equipment	$12,116	$11,603	$12,827	$0	$0	**$36,546**	$3,471	$0	$8,277	**$48,294**	$75
	SUBTOTAL 4	**$266,809**	**$11,603**	**$69,396**	**$0**	**$0**	**$347,808**	**$32,521**	**$21,881**	**$54,930**	**$457,140**	**$714**
5A	Gas Cleanup & Piping	$46,447	$4,978	$47,184	$0	$0	**$98,610**	$9,456	$89	$21,825	**$129,980**	$203
5B	CO_2 REMOVAL & COMPRESSION	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$82,000	$0	$5,071	$0	$0	**$87,072**	$8,192	$4,354	$9,962	**$109,578**	$171
6.2-6.9	Combustion Turbine Other	$5,440	$752	$1,598	$0	$0	**$7,791**	$733	$0	$1,539	**$10,063**	$16
	SUBTOTAL 6	**$87,441**	**$752**	**$6,670**	**$0**	**$0**	**$94,862**	**$8,925**	**$4,354**	**$11,501**	**$119,642**	**$187**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$34,012	$0	$4,840	$0	$0	**$38,851**	$3,667	$0	$4,252	**$46,771**	$73
7.2-7.9	Ductwork and Stack	$3,127	$2,201	$2,922	$0	$0	**$8,249**	$762	$0	$1,465	**$10,476**	$16
	SUBTOTAL 7	**$37,138**	**$2,201**	**$7,761**	**$0**	**$0**	**$47,101**	**$4,429**	**$0**	**$5,717**	**$57,247**	**$89**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$29,570	$0	$5,065	$0	$0	**$34,635**	$3,319	$0	$3,795	**$41,750**	$65
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$10,895	$1,003	$7,554	$0	$0	**$19,452**	$1,756	$0	$4,243	**$25,451**	$40
	SUBTOTAL 8	**$40,465**	**$1,003**	**$12,619**	**$0**	**$0**	**$54,087**	**$5,075**	**$0**	**$8,039**	**$67,201**	**$105**
9	COOLING WATER SYSTEM	$7,199	$7,656	$6,445	$0	$0	**$21,301**	$1,957	$0	$4,774	**$28,032**	$44
10	ASH/SPENT SORBENT HANDLING SYS	$14,077	$7,868	$14,278	$0	$0	**$36,223**	$3,463	$0	$4,274	**$43,960**	$69
11	ACCESSORY ELECTRIC PLANT	$23,161	$10,196	$20,591	$0	$0	**$53,947**	$4,678	$0	$11,201	**$69,826**	$109
12	INSTRUMENTATION & CONTROL	$9,437	$1,767	$6,335	$0	$0	**$17,538**	$1,616	$877	$3,351	**$23,382**	$37
13	IMPROVEMENTS TO SITE	$3,211	$1,892	$7,981	$0	$0	**$13,084**	$1,285	$0	$4,311	**$18,681**	$29
14	BUILDINGS & STRUCTURES	$0	$6,373	$7,450	$0	$0	**$13,823**	$1,257	$0	$2,462	**$17,541**	$27
	TOTAL COST	**$581,977**	**$71,760**	**$240,644**	**$0**	**$0**	**$894,382**	**$83,439**	**$28,701**	**$154,397**	**$1,160,919**	**$1,813**

Exhibit 3-30 Case 1 Total Plant Cost Details

Client: USDOE/NETL — Report Date: 05-Apr-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 01 - GEE Radiant Only IGCC w/o CO2
Plant Size: 640.3 MW,net — Estimate Type: Conceptual — Cost Base (Dec) 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	$3,547	$0	$1,751	$0	$0	$5,298	$474	$0	$1,154	$6,926	$11
1.2	Coal Stackout & Reclaim	$4,583	$0	$1,123	$0	$0	$5,706	$500	$0	$1,241	$7,447	$12
1.3	Coal Conveyors	$4,261	$0	$1,111	$0	$0	$5,372	$472	$0	$1,169	$7,012	$11
1.4	Other Coal Handling	$1,115	$0	$257	$0	$0	$1,372	$120	$0	$298	$1,790	$3
1.5	Sorbent Receive & Unload	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.6	Sorbent Stackout & Reclaim	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.7	Sorbent Conveyors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.8	Other Sorbent Handling	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.9	Coal & Sorbent Hnd.Foundations	$0	$2,518	$6,341	$0	$0	$8,859	$844	$0	$1,941	$11,643	$18
	SUBTOTAL 1.	**$13,505**	**$2,518**	**$10,582**	**$0**	**$0**	**$26,606**	**$2,410**	**$0**	**$5,803**	**$34,819**	**$54**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying incl w/2.3	incl. w/ 2.3	incl. w/ 2.3	incl. w/ 2.3	$0	$0	$0	$0	$0	$0	$0	$0
2.2	Prepared Coal Storage & Feed	$1,515	$361	$240	$0	$0	$2,116	$181	$0	$459	$2,757	$4
2.3	Slurry Prep & Feed	$20,764	$0	$9,236	$0	$0	$30,000	$2,719	$1,500	$6,844	$41,063	$64
2.4	Misc.Coal Prep & Feed	$833	$603	$1,837	$0	$0	$3,273	$300	$0	$715	$4,288	$7
2.5	Sorbent Prep Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.6	Sorbent Storage & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.7	Sorbent Injection System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.8	Booster Air Supply System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.9	Coal & Sorbent Feed Foundation	$0	$3,249	$2,686	$0	$0	$5,936	$548	$0	$1,297	$7,780	$12
	SUBTOTAL 2.	**$23,112**	**$4,213**	**$13,999**	**$0**	**$0**	**$41,324**	**$3,748**	**$1,500**	**$9,315**	**$55,887**	**$87**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	$3,484	$6,058	$3,201	$0	$0	$12,743	$1,176	$0	$2,784	$16,703	$26
3.2	Water Makeup & Pretreating	$532	$55	$297	$0	$0	$884	$83	$0	$290	$1,258	$2
3.3	Other Feedwater Subsystems	$1,924	$652	$587	$0	$0	$3,164	$283	$0	$689	$4,136	$6
3.4	Service Water Systems	$306	$625	$2,172	$0	$0	$3,104	$300	$0	$1,021	$4,426	$7
3.5	Other Boiler Plant Systems	$1,646	$632	$1,567	$0	$0	$3,845	$360	$0	$841	$5,046	$8
3.6	FO Supply Sys & Nat Gas	$306	$577	$539	$0	$0	$1,421	$136	$0	$311	$1,868	$3
3.7	Waste Treatment Equipment	$739	$0	$453	$0	$0	$1,192	$116	$0	$392	$1,700	$3
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	$1,038	$139	$537	$0	$0	$1,715	$165	$0	$564	$2,444	$4
	SUBTOTAL 3.	**$9,975**	**$8,740**	**$9,353**	**$0**	**$0**	**$28,067**	**$2,620**	**$0**	**$6,893**	**$37,580**	**$59**
4	GASIFIER & ACCESSORIES											
4.1	Syngas Cooler Gasifier System	$101,906	$0	$56,569	$0	$0	$158,475	$14,508	$21,881	$29,920	$224,784	$351
4.2	Syngas Cooler(w/ Gasifier - 4.1)	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.3	ASU/Oxidant Compression	$152,787	$0	w/equip.	$0	$0	$152,787	$14,542	$0	$16,733	$184,063	$287
4.4	Scrubber & Low Temperature Cooling	$9,253	$7,518	$7,846	$0	$0	$24,617	$2,346	$0	$5,393	$32,356	$51
4.5	Black Water & Sour Gas Section	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.6	Other Gasification Equipment	$2,863	$1,359	$2,689	$0	$0	$6,911	$661	$0	$1,514	$9,087	$14
4.8	Major Component Rigging	w/4.1&4.2	$0	w/4.1&4.2	$0	$0	$0	$0	$0	$0	$0	$0
4.9	Gasification Foundations	$0	$2,726	$2,292	$0	$0	$5,018	$463	$0	$1,370	$6,851	$11
	SUBTOTAL 4.	**$266,809**	**$11,603**	**$69,396**	**$0**	**$0**	**$347,808**	**$32,521**	**$21,881**	**$54,930**	**$457,140**	**$714**

Exhibit 3-30 Case 1 Total Plant Costs (Continued)

Client: USDOE/NETL **Report Date:** 05-Apr-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 01 - GEE Radiant Only IGCC w/o CO2
Plant Size: 640.3 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5A	GAS CLEANUP & PIPING											
5A.1	Single Stage Selexol	$33,056	$0	$28,354	$0	$0	$61,411	$5,895	$0	$13,461	$80,767	$126
5A.2	Elemental Sulfur Plant	$9,860	$1,957	$12,731	$0	$0	$24,548	$2,367	$0	$5,383	$32,299	$50
5A.3	Mercury Removal	$1,016	$0	$774	$0	$0	$1,790	$172	$89	$410	$2,461	$4
5A.4	COS Hydrolysis	$2,515	$0	$3,286	$0	$0	$5,801	$560	$0	$1,272	$7,633	$12
5A.5	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.6	Blowback Gas Systems	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.7	Fuel Gas Piping	$0	$1,942	$1,338	$0	$0	$3,280	$299	$0	$716	$4,294	$7
5A.9	HGCU Foundations	$0	$1,079	$701	$0	$0	$1,780	$163	$0	$583	$2,527	$4
	SUBTOTAL 5A.	**$46,447**	**$4,978**	**$47,184**	**$0**	**$0**	**$98,610**	**$9,456**	**$89**	**$21,825**	**$129,980**	**$203**
5B	CO2 REMOVAL & COMPRESSION											
5B.1	CO2 Removal System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5B.2	CO2 Compression & Drying	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 5B.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$82,000	$0	$5,071	$0	$0	$87,072	$8,192	$4,354	$9,962	$109,578	$171
6.2	Syngas Expander	$5,440	$0	$760	$0	$0	$6,200	$585	$0	$1,018	$7,803	$12
6.3	Compressed Air Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.9	Combustion Turbine Foundations	$0	$752	$838	$0	$0	$1,591	$148	$0	$522	$2,260	$4
	SUBTOTAL 6.	**$87,441**	**$752**	**$6,670**	**$0**	**$0**	**$94,862**	**$8,925**	**$4,354**	**$11,501**	**$119,642**	**$187**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$34,012	$0	$4,840	$0	$0	$38,851	$3,667	$0	$4,252	$46,771	$73
7.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$0	$1,579	$1,144	$0	$0	$2,723	$239	$0	$592	$3,555	$6
7.4	Stack	$3,127	$0	$1,175	$0	$0	$4,302	$409	$0	$471	$5,182	$8
7.9	HRSG,Duct & Stack Foundations	$0	$622	$602	$0	$0	$1,225	$114	$0	$401	$1,739	$3
	SUBTOTAL 7.	**$37,138**	**$2,201**	**$7,761**	**$0**	**$0**	**$47,101**	**$4,429**	**$0**	**$5,717**	**$57,247**	**$89**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$29,570	$0	$5,065	$0	$0	$34,635	$3,319	$0	$3,795	$41,750	$65
8.2	Turbine Plant Auxiliaries	$204	$0	$467	$0	$0	$670	$65	$0	$74	$809	$1
8.3	Condenser & Auxiliaries	$5,181	$0	$1,496	$0	$0	$6,678	$634	$0	$731	$8,042	$13
8.4	Steam Piping	$5,510	$0	$3,883	$0	$0	$9,393	$801	$0	$2,549	$12,744	$20
8.9	TG Foundations	$0	$1,003	$1,707	$0	$0	$2,711	$256	$0	$890	$3,856	$6
	SUBTOTAL 8.	**$40,465**	**$1,003**	**$12,619**	**$0**	**$0**	**$54,087**	**$5,075**	**$0**	**$8,039**	**$67,201**	**$105**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$4,704	$0	$1,034	$0	$0	$5,738	$543	$0	$942	$7,223	$11
9.2	Circulating Water Pumps	$1,481	$0	$95	$0	$0	$1,575	$135	$0	$257	$1,967	$3
9.3	Circ.Water System Auxiliaries	$122	$0	$17	$0	$0	$139	$13	$0	$23	$175	$0
9.4	Circ.Water Piping	$0	$5,160	$1,316	$0	$0	$6,476	$573	$0	$1,410	$8,460	$13
9.5	Make-up Water System	$299	$0	$424	$0	$0	$723	$69	$0	$158	$949	$1
9.6	Component Cooling Water Sys	$594	$711	$502	$0	$0	$1,808	$167	$0	$395	$2,370	$4
9.9	Circ.Water System Foundations& Structures	$0	$1,785	$3,057	$0	$0	$4,842	$457	$0	$1,590	$6,889	$11
	SUBTOTAL 9.	**$7,199**	**$7,656**	**$6,445**	**$0**	**$0**	**$21,301**	**$1,957**	**$0**	**$4,774**	**$28,032**	**$44**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Slag Dewatering & Cooling	$11,592	$6,392	$12,995	$0	$0	$30,979	$2,968	$0	$3,395	$37,341	$58
10.2	Gasifier Ash Depressurization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.3	Cleanup Ash Depressurization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.4	High Temperature Ash Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.5	Other Ash Rrecovery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$562	$0	$612	$0	$0	$1,174	$113	$0	$193	$1,480	$2
10.7	Ash Transport & Feed Equipment	$759	$0	$182	$0	$0	$941	$87	$0	$154	$1,182	$2
10.8	Misc. Ash Handling Equipment	$1,164	$1,427	$426	$0	$0	$3,017	$285	$0	$495	$3,798	$6
10.9	Ash/Spent Sorbent Foundation	$0	$49	$62	$0	$0	$112	$10	$0	$37	$159	$0
	SUBTOTAL 10.	**$14,077**	**$7,868**	**$14,278**	**$0**	**$0**	**$36,223**	**$3,463**	**$0**	**$4,274**	**$43,960**	**$69**

Exhibit 3-30 Case 1 Total Plant Cost Details (Continued)

Client: USDOE/NETL **Report Date:** 05-Apr-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 01 - GEE Radiant Only IGCC w/o CO2
Plant Size: 640.3 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$921	$0	$918	$0	$0	$1,839	$175	$0	$201	$2,215	$3
11.2	Station Service Equipment	$3,646	$0	$342	$0	$0	$3,988	$379	$0	$437	$4,804	$8
11.3	Switchgear & Motor Control	$6,967	$0	$1,277	$0	$0	$8,245	$764	$0	$1,351	$10,360	$16
11.4	Conduit & Cable Tray	$0	$3,315	$10,762	$0	$0	$14,077	$1,346	$0	$3,856	$19,279	$30
11.5	Wire & Cable	$0	$6,088	$4,095	$0	$0	$10,184	$744	$0	$2,732	$13,660	$21
11.6	Protective Equipment	$0	$640	$2,427	$0	$0	$3,067	$300	$0	$505	$3,872	$6
11.7	Standby Equipment	$218	$0	$222	$0	$0	$441	$43	$0	$72	$556	$1
11.8	Main Power Transformers	$11,408	$0	$142	$0	$0	$11,550	$875	$0	$1,864	$14,288	$22
11.9	Electrical Foundations	$0	$153	$404	$0	$0	$557	$53	$0	$183	$793	$1
	SUBTOTAL 11.	**$23,161**	**$10,196**	**$20,591**	**$0**	**$0**	**$53,947**	**$4,678**	**$0**	**$11,201**	**$69,826**	**$109**
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
12.3	Steam Turbine Control	w/8.1	$0	w/8.1	$0	$0	$0	$0	$0	$0	$0	$0
12.4	Other Major Component Control	$932	$0	$648	$0	$0	$1,580	$152	$79	$272	$2,082	$3
12.5	Signal Processing Equipment	W/12.7	$0	W/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.6	Control Boards,Panels & Racks	$214	$0	$143	$0	$0	$357	$34	$18	$82	$491	$1
12.7	Computer & Accessories	$4,969	$0	$166	$0	$0	$5,135	$487	$257	$588	$6,466	$10
12.8	Instrument Wiring & Tubing	$0	$1,767	$3,697	$0	$0	$5,464	$463	$273	$1,550	$7,751	$12
12.9	Other I & C Equipment	$3,322	$0	$1,681	$0	$0	$5,002	$480	$250	$860	$6,592	$10
	SUBTOTAL 12.	**$9,437**	**$1,767**	**$6,335**	**$0**	**$0**	**$17,538**	**$1,616**	**$877**	**$3,351**	**$23,382**	**$37**
13	Improvements to Site											
13.1	Site Preparation	$0	$101	$2,169	$0	$0	$2,270	$224	$0	$748	$3,242	$5
13.2	Site Improvements	$0	$1,792	$2,399	$0	$0	$4,190	$412	$0	$1,381	$5,983	$9
13.3	Site Facilities	$3,211	$0	$3,413	$0	$0	$6,624	$650	$0	$2,182	$9,457	$15
	SUBTOTAL 13.	**$3,211**	**$1,892**	**$7,981**	**$0**	**$0**	**$13,084**	**$1,285**	**$0**	**$4,311**	**$18,681**	**$29**
14	Buildings & Structures											
14.1	Combustion Turbine Area	$0	$221	$127	$0	$0	$348	$31	$0	$76	$454	$1
14.2	Steam Turbine Building	$0	$2,410	$3,479	$0	$0	$5,888	$540	$0	$964	$7,393	$12
14.3	Administration Building	$0	$802	$590	$0	$0	$1,392	$124	$0	$227	$1,743	$3
14.4	Circulation Water Pumphouse	$0	$158	$85	$0	$0	$243	$21	$0	$40	$304	$0
14.5	Water Treatment Buildings	$0	$423	$418	$0	$0	$842	$76	$0	$138	$1,055	$2
14.6	Machine Shop	$0	$411	$285	$0	$0	$695	$62	$0	$114	$871	$1
14.7	Warehouse	$0	$663	$434	$0	$0	$1,097	$97	$0	$179	$1,373	$2
14.8	Other Buildings & Structures	$0	$397	$313	$0	$0	$710	$63	$0	$155	$929	$1
14.9	Waste Treating Building & Str.	$0	$888	$1,719	$0	$0	$2,607	$242	$0	$570	$3,419	$5
	SUBTOTAL 14.	**$0**	**$6,373**	**$7,450**	**$0**	**$0**	**$13,823**	**$1,257**	**$0**	**$2,462**	**$17,541**	**$27**
	TOTAL COST	**$581,977**	**$71,760**	**$240,644**	**$0**	**$0**	**$894,382**	**$83,439**	**$28,701**	**$154,397**	**$1,160,919**	**$1,813**

Exhibit 3-31 Case 1 Initial and Annual O&M Costs

INITIAL & ANNUAL O&M EXPENSES

Case 01 - GEE Radiant Only IGCC w/o CO2

Cost Base (Dec)	2006
Heat Rate-net(Btu/kWh):	8,922
MWe-net:	640
Capacity Factor: (%):	80

OPERATING & MAINTENANCE LABOR

Operating Labor

Operating Labor Rate(base):	33.00	$/hour
Operating Labor Burden:	30.00	% of base
Labor O-H Charge Rate:	25.00	% of labor

		Total
Skilled Operator	2.0	2.0
Operator	9.0	9.0
Foreman	1.0	1.0
Lab Tech's, etc.	3.0	3.0
TOTAL-O.J.'s	15.0	15.0

	Annual Cost $	Annual Unit Cost $/kW-net
Annual Operating Labor Cost	$5,637,060	$8.804
Maintenance Labor Cost	$12,434,373	$19.421
Administrative & Support Labor	$4,517,858	$7.056
TOTAL FIXED OPERATING COSTS	**$22,589,291**	**$35.282**

VARIABLE OPERATING COSTS

Consumables	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost	Annual Cost $	$/kWh-net
Maintenance Material Cost					**$23,111,454**	**$0.00515**
Water(/1000 gallons)	0	5,874	1.03	**$0**	**$1,766,592**	**$0.00039**
Chemicals						
MU & WT Chem.(lb)	122,480	17,497	0.16	$20,185	$841,987	$0.00019
Carbon (Mercury Removal) (lb)	59,493	81	1.00	$59,493	$23,652	$0.00001
COS Catalyst (m3)	410	0.28	2,308.40	$946,446	$189,160	$0.00004
Water Gas Shift Catalyst(ft3)	0	0	475.00	$0	$0	$0.00000
Selexol Solution (gal)	378	54	12.90	$4,877	$203,424	$0.00005
MDEA Solution (gal)	0	0	0.96	$0	$0	$0.00000
Sulfinol Solution (gal)	0	0	9.68	$0	$0	$0.00000
SCR Catalyst (m3)	0	0	0.00	$0	$0	$0.00000
Aqueous Ammonia (ton)	0	0	0.00	$0	$0	$0.00000
Claus Catalyst(ft3)	w/equip.	2.21	125.00	$0	$80,745	$0.00002
Subtotal Chemicals				**$1,031,000**	**$1,338,968**	**$0.00030**
Other						
Supplemental Fuel(MBtu)	0	0	0.00	$0	$0	$0.00000
Gases,N2 etc.(/100scf)	0	0	0.00	$0	$0	$0.00000
L.P. Steam(/1000 pounds)	0	0	0.00	$0	$0	$0.00000
Subtotal Other				**$0**	**$0**	**$0.00000**
Waste Disposal						
Spent Mercury Catalyst (lb)	0	81	0.40	$0	$9,499	$0.00000
Flyash (ton)	0	0	0.00	$0	$0	$0.00000
Bottom Ash(ton)	0	645	15.45	$0	$2,909,636	$0.00065
Subtotal-Waste Disposal				**$0**	**$2,919,135**	**$0.00065**
By-products & Emissions						
Sulfur(tons)	0	147	0.00	$0	$0	$0.00000
Subtotal By-Products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$1,031,000**	**$29,136,149**	**$0.00649**
Fuel(ton)	176,276	5,876	42.11	**$7,422,978**	**$72,250,323**	**$0.01610**

3.2.8 CASE 2 - GEE IGCC WITH CO_2 CAPTURE

Case 2 is configured to produce electric power with CO_2 capture. The plant configuration is the same as Case 1, namely two gasifier trains, two advanced F Class turbines, two HRSGs and one steam turbine. The gross power output from the plant is constrained by the capacity of the two combustion turbines, and since the CO_2 capture process increases the auxiliary load on the plant, the net output is significantly reduced relative to Case 1.

The process description for Case 2 is similar to Case 1 with several notable exceptions to accommodate CO_2 capture. A BFD and stream tables for Case 2 are shown in Exhibit 3-32 and Exhibit 3-33, respectively. Instead of repeating the entire process description, only differences from Case 1 are reported here.

Gasification

The gasification process is the same as Case 1 with the exception that total coal feed to the two gasifiers is 5,448 tonnes/day (6,005 TPD) (stream 6) and the ASU provides 4,635 tonnes/day (5,110 TPD) of 95 percent oxygen to the gasifier and Claus plant (streams 3 and 5).

Raw Gas Cooling/Particulate Removal

Raw gas cooling and particulate removal are the same as Case 1 with the exception that approximately 548,122 kg/h (1,208,400 lb/h) of saturated steam at 13.8 MPa (2,000 psia) is generated in the radiant SGCs.

Syngas Scrubber/Sour Water Stripper

No differences from Case 1.

Sour Gas Shift (SGS)

The SGS process was described in Section 3.1.3. In Case 2 steam (stream 10) is added to the syngas exiting the scrubber to adjust the H_2O:CO molar ratio to 2:1 prior to the first SGS reactor. The hot syngas exiting the first stage of SGS is used to generate the steam that is added in stream 10. A second stage of SGS results in 96 percent overall conversion of the CO to CO_2. The warm syngas from the second stage of SGS (stream 11) is cooled to 232°C (450°F) by producing IP steam that is sent to the reheater in the HRSG. The SGS catalyst also serves to hydrolyze COS thus eliminating the need for a separate COS hydrolysis reactor. Following the second SGS cooler the syngas is further cooled to 39°C (103°F) prior to the mercury removal beds.

Mercury Removal and Acid Gas Removal

Mercury removal is the same as in Case 1.

The AGR process in Case 2 is a two stage Selexol process where H_2S is removed in the first stage and CO_2 in the second stage of absorption as previously described in Section 3.1.5. The process results in three product streams, the clean syngas, a CO_2-rich stream and an acid gas feed to the Claus plant. The acid gas (stream 17) contains 41 percent H_2S and 45 percent CO_2 with the balance primarily N_2. The CO_2-rich stream is discussed further in the CO_2 compression section.

Exhibit 3-32 Case 2 Process Flow Diagram, GEE IGCC with CO_2 Capture

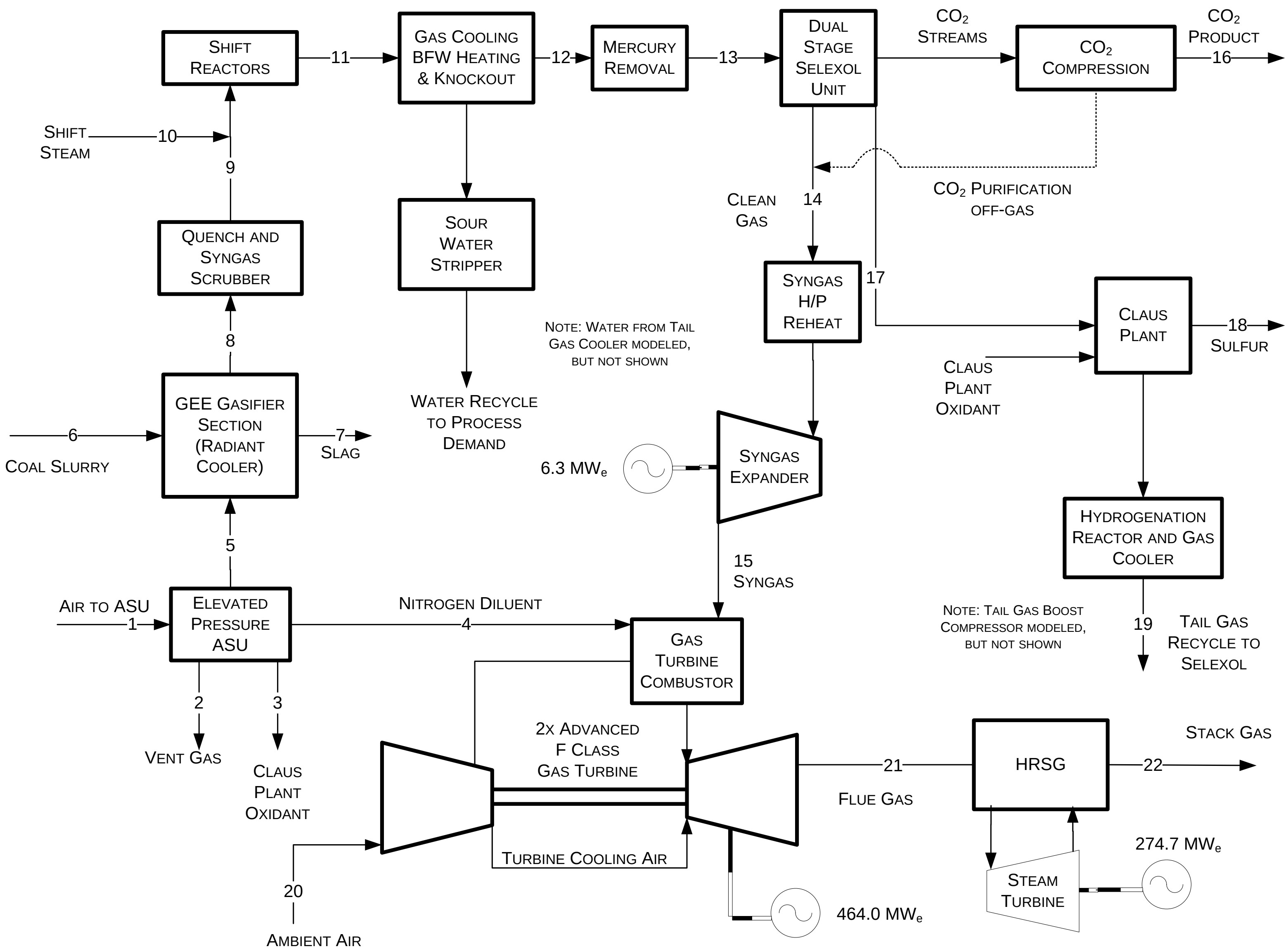

Exhibit 3-33 Case 2 Stream Table, GEE IGCC with CO_2 Capture

	1	2	3	4	5	6[A]	7	8	9	10	11
V-L Mole Fraction											
Ar	0.0094	0.0089	0.0360	0.0024	0.0320	0.0000	0.0000	0.0079	0.0062	0.0000	0.0051
CH_4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0010	0.0008	0.0000	0.0006
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3442	0.2666	0.0000	0.0090
CO_2	0.0003	0.0023	0.0000	0.0000	0.0000	0.0000	0.0000	0.1511	0.1166	0.0000	0.3113
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0002	0.0001	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3349	0.2594	0.0000	0.4305
H_2O	0.0108	0.0836	0.0000	0.0000	0.0000	1.0000	0.0000	0.1429	0.3365	1.0000	0.2317
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0073	0.0056	0.0000	0.0048
N_2	0.7719	0.8367	0.0140	0.9922	0.0180	0.0000	0.0000	0.0089	0.0069	0.0000	0.0058
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0017	0.0013	0.0000	0.0011
O_2	0.2076	0.0685	0.9500	0.0054	0.9500	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	64,331	8,321	214	42,780	13,015	14,511	0	52,422	67,674	13,313	80,987
V-L Flowrate (lb/hr)	1,855,930	229,617	6,904	1,200,560	418,847	261,198	0	1,069,860	1,343,900	239,846	1,583,740
Solids Flowrate (lb/hr)	0	0	0	0	0	444,737	54,925	0	0	0	0
Temperature (°F)	232	60	90	385	206	141	410	1,100	410	615	519
Pressure (psia)	190.6	16.4	145.0	460.0	980.0	1,050.0	797.7	799.7	797.7	875.0	777.2
Enthalpy (BTU/lb)[B]	55.6	18.0	12.5	87.8	37.7	---	1,710	535.5	474.7	1275.0	433.3
Density (lb/ft^3)	0.741	0.087	0.792	1.424	4.416	---	---	0.975	1.697	1.367	1.447
Molecular Weight	28.849	27.594	32.229	28.063	32.181	---	---	20.409	19.858	18.015	19.555

A - Solids flowrate includes dry coal; V-L flowrate includes slurry water and water from coal

B - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 3-33 Case 2 Stream Table (continued)

	12	13	14	15	16	17	18	19	20	21	22
V-L Mole Fraction											
Ar	0.0067	0.0067	0.0111	0.0111	0.0000	0.0000	0.0000	0.0182	0.0094	0.0092	0.0092
CH_4	0.0008	0.0008	0.0022	0.0022	0.0000	0.0000	0.0000	0.0577	0.0000	0.0000	0.0000
CO	0.0117	0.0117	0.0190	0.0190	0.0000	0.0000	0.0000	0.0003	0.0000	0.0000	0.0000
CO_2	0.4057	0.4057	0.0448	0.0448	1.0000	0.4488	0.0000	0.6784	0.0003	0.0085	0.0085
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0005	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.5609	0.5609	0.9095	0.9095	0.0000	0.0000	0.0000	0.0170	0.0000	0.0000	0.0000
H_2O	0.0009	0.0009	0.0000	0.0000	0.0000	0.0394	0.0000	0.0005	0.0108	0.1226	0.1226
H_2S	0.0054	0.0054	0.0000	0.0000	0.0000	0.4102	0.0000	0.0228	0.0000	0.0000	0.0000
N_2	0.0075	0.0075	0.0134	0.0134	0.0000	0.0807	0.0000	0.2051	0.7719	0.7527	0.7527
NH_3	0.0003	0.0003	0.0000	0.0000	0.0000	0.0203	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2076	0.1071	0.1071
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	62,118	62,118	38,323	38,323	23,493	855	0	576	243,972	307,285	307,285
V-L Flowrate (lb/hr)	1,243,070	1,243,070	198,981	198,981	1,033,930	31,703	0	21,951	7,038,470	8,438,010	8,438,010
Solids Flowrate (lb/hr)	0	0	0	0	0	0	12,514	0	0	0	0
Temperature (°F)	103	103	100	386	155	120	373	95	59	1,052	270
Pressure (psia)	736.7	726.7	696.2	460.0	2,214.7	30.5	25.4	776.1	14.7	15.2	15.2
Enthalpy (BTU/lb)[B]	28.0	28.0	91.4	480.6	-46.5	39.7	-96.5	14.0	13.8	361.5	148.2
Density (lb/ft^3)	2.443	2.410	0.602	0.263	30.975	0.184	---	4.966	0.076	0.026	0.053
Molecular Weight	20.012	20.012	5.192	5.192	44.010	37.082	---	38.086	28.849	27.460	27.460

B - Reference conditions are 32.02 F & 0.089 PSIA

CO_2 Compression and Dehydration

CO_2 from the AGR process is generated at three pressure levels. The LP stream is compressed from 0.15 MPa (22 psia) to 1.1 MPa (160 psia) and then combined with the MP stream. The HP stream is combined between compressor stages at 2.1 MPa (300 psia). The combined stream is compressed from 2.1 MPa (300 psia) to a supercritical condition at 15.3 MPa (2215 psia) using a multiple-stage, intercooled compressor. During compression, the CO_2 stream is dehydrated to a dewpoint of -40ºC (-40°F) with triethylene glycol. The raw CO_2 stream from the Selexol process contains over 93 percent CO_2 with the balance primarily nitrogen. For modeling purposes it was assumed that the impurities were separated from the CO_2 and combined with the clean syngas stream from the Selexol process. The pure CO_2 (stream 16) is transported to the plant fence line and is sequestration ready. CO_2 TS&M costs were estimated using the methodology described in Section 2.7.

Claus Unit

The Claus plant is the same as Case 1 with the following exceptions:

- 5,676 kg/h (12,514 lb/h) of sulfur (stream 18) are produced
- The waste heat boiler generates 13,555 (29,884 lb/h) of 4.0 MPa (575 psia) steam of which 9,603 kg/h (21,172 lb/h) is available to the medium pressure steam header.

Power Block

Clean syngas from the AGR plant is combined with a small amount of clean gas from the CO_2 compression process (stream 14) and heated to 465°F using HP boiler feedwater before passing through an expansion turbine. The clean syngas (stream 15) is diltuted with nitrogen (stream 4) and then enters the CT burner. There is no integration between the CT and the ASU in this case. The exhaust gas (stream 21) exits the CT at 567°C (1052°F) and enters the HRSG where additional heat is recovered. The flue gas exits the HRSG at 132°C (270°F) (stream 22) and is discharged through the plant stack. The steam raised in the HRSG is used to power an advanced commercially available steam turbine using a 12.4 MPa/538°C/538°C (1800 psig/1000°F/1000°F) steam cycle.

Air Separation Unit

The same elevated pressure ASU is used in Case 2 and produces 4,635 tonnes/day (5,110 TPD) of 95 mole percent oxygen and 13,070 tonnes/day (14,410 TPD) of nitrogen. There is no integration between the ASU and the combustion turbine.

3.2.9 CASE 2 PERFORMANCE RESULTS

The Case 2 modeling assumptions were presented previously in Section 3.2.3.

The plant produces a net output of 556 MW at a net plant efficiency of 32.5 percent (HHV basis). Overall performance for the entire plant is summarized in Exhibit 3-34 which includes auxiliary power requirements. The ASU accounts for nearly 64 percent of the auxiliary load between the main air compressor, the nitrogen compressor, the oxygen compressor and ASU auxiliaries. The two-stage Selexol process and CO_2 compression account for an additional 24 percent of the auxiliary power load. The BFW pumps and cooling water system (circulating water pumps and cooling tower fan) comprise over 5 percent of the load, leaving 7 percent of the auxiliary load for all other systems.

Exhibit 3-34 Case 2 Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine Power	464,010
Sweet Gas Expander Power	6,260
Steam Turbine Power	274,690
TOTAL POWER, kWe	**744,960**
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	460
Coal Milling	2,330
Coal Slurry Pumps	760
Slag Handling and Dewatering	1,200
Air Separation Unit Auxiliaries	1,000
Air Separation Unit Main Air Compressor	72,480
Oxygen Compressor	11,520
Nitrogen Compressor	35,870
Claus Plant Tail Gas Recycle Compressor	990
CO_2 Compressor	27,400
Boiler Feedwater Pumps	4,580
Condensate Pump	265
Flash Bottoms Pump	200
Circulating Water Pumps	3,580
Cooling Tower Fans	1,850
Scrubber Pumps	420
Selexol Unit Auxiliaries	17,320
Gas Turbine Auxiliaries	1,000
Steam Turbine Auxiliaries	100
Claus Plant/TGTU Auxiliaries	200
Miscellaneous Balance of Plant (Note 1)	3,000
Transformer Loss	2,760
TOTAL AUXILIARIES, kWe	**189,285**
NET POWER, kWe	**555,675**
Net Plant Efficiency, % (HHV)	32.5
Net Plant Heat Rate (Btu/kWh)	10,505
CONDENSER COOLING DUTY 10^6 kJ/h (10^6 Btu/h)	**1,509 (1,431)**
CONSUMABLES	
As-Received Coal Feed, kg/h (lb/h)	226,968 (500,379)
Thermal Input, kWt	1,710,780
Raw Water Usage, m^3/min (gpm)	8.7 (4,578)

Note 1: Includes plant control systems, lighting, HVAC and miscellaneous low voltage loads

Environmental Performance

The environmental targets for emissions of Hg, NOx, SO2, and particulate matter were presented in Section 2.4. A summary of the plant air emissions for Case 2 is presented in Exhibit 3-35.

Exhibit 3-35 Case 2 Air Emissions

	kg/GJ ($lb/10^6$ Btu)	Tonne/year (tons/year) @ 80% capacity factor	kg/MWh (lb/MWh)
SO_2	0.004 (0.010)	178 (196)	0.034 (0.075)
NO_X	0.020 (0.047)	867 (955)	0.166 (0.366)
Particulates	0.003 (0.0071)	132 (145)	0.025 (0.056)
Hg	$0.25x10^{-6}$ ($0.57x10^{-6}$)	0.011 (0.012)	$2.0x10^{-6}$ ($4.5x10^{-6}$)
CO_2	8.4 (19.6)	364,000 (401,000)	70 (154)
CO_2[1]			93 (206)

[1] CO_2 emissions based on net power instead of gross power

The low level of SO_2 emissions is achieved by capture of the sulfur in the gas by the two-stage Selexol AGR process. As a result of achieving the 90 percent CO_2 removal target, the sulfur compounds are removed to an extent that exceeds the environmental target in Section 2.4. The clean syngas exiting the AGR process has a sulfur concentration of approximately 23 ppmv. This results in a concentration in the flue gas of less than 3 ppmv. The H_2S-rich regeneration gas from the AGR system is fed to a Claus plant, producing elemental sulfur. The Claus plant tail gas is hydrogenated to convert all sulfur species to H_2S and then recycled back to the Selexol process, thereby eliminating the need for a tail gas treatment unit.

NO_X emissions are limited by nitrogen dilution to 15 ppmvd (as NO_2 @15 percent O_2). Ammonia in the syngas is removed with process condensate prior to the low-temperature AGR process. This helps lower NO_X levels as well.

Particulate discharge to the atmosphere is limited to extremely low values by the use of the syngas quench in addition to the syngas scrubber and the gas washing effect of the AGR absorber. The particulate emissions represent filterable particulate only.

Ninety five percent of mercury is captured from the syngas by an activated carbon bed. Ninety percent of the CO_2 from the syngas is captured in the AGR system and compressed for sequestration.

The carbon balance for the plant is shown in Exhibit 3-36. The carbon input to the plant consists of carbon in the air in addition to carbon in the coal. Carbon in the air is not neglected here since the AspenPlus model accounts for air components throughout. Carbon leaves the plant as unburned carbon in the slag, as dissolved CO_2 in the wastewater blowdown stream, and as CO_2 in the stack gas, ASU vent gas, and the captured CO_2 product. Carbon in the wastewater blowdown stream is calculated by difference to close the material balance. The carbon capture efficiency is defined as the amount of carbon in the CO_2 product stream relative to the amount of carbon in the coal less carbon contained in the slag, represented by the following fraction:

(Carbon in CO_2 Product)/[(Carbon in the Coal)-(Carbon in Slag)] or
281,981/(318,992-6,404) *100 or
90.2 percent

Exhibit 3-36 Case 2 Carbon Balance

Carbon In, kg/hr (lb/hr)		Carbon Out, kg/hr (lb/hr)	
Coal	144,692 (318,992)	**Slag**	2,905 (6,404)
Air (CO_2)	495 (1,091)	**Stack Gas**	14,162 (31,221)
		CO_2 Product	127,904 (281,981)
		ASU Vent	103 (228)
		Wastewater	113 (249)
Total	145,187 (320,083)	**Total**	145,187 (320,083)

Exhibit 3-37 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered in the Claus plant, dissolved SO_2 in the wastewater blowdown stream, and sulfur emitted in the stack gas. Sulfur in the slag is considered to be negligible, and the sulfur content of the blowdown stream is calculated by difference to close the material balance. The total sulfur capture is represented by the following fraction:

(Sulfur byproduct/Sulfur in the coal) or
(12,514/12,560) or
99.6 percent

Exhibit 3-37 Case 2 Sulfur Balance

Sulfur In, kg/hr (lb/hr)		Sulfur Out, kg/hr (lb/hr)	
Coal	5,697 (12,560)	**Elemental Sulfur**	5,676 (12,514)
		Stack Gas	13 (28)
		Wastewater	8 (18)
Total	5,697 (12,560)	**Total**	5,697 (12,560)

Exhibit 3-38 shows the overall water balance for the plant. Raw water is obtained from groundwater (50 percent) and from municipal sources (50 percent). Water demand represents the total amount of water required for a particular process. Some water is recovered within the process, primarily as syngas condensate, and that water is re-used as internal recycle. Raw water makeup is the difference between water demand and internal recycle.

Exhibit 3-38 Case 2 Water Balance

Water Use	Water Demand, m^3/min (gpm)	Internal Recycle, m^3/min (gpm)	Raw Water Makeup, m^3/min (gpm)
Slurry	1.6 (411)	1.6 (411)	0
Slag Handling	0.5 (143)	0	0.5 (143)
Quench/Scrubber	2.5 (665)	1.2 (315)	1.3 (350)
Shift Steam	1.8 (479)	0	1.8 (479)
BFW Makeup	0.2 (45)	0	0.2 (45)
Cooling Tower Makeup	13.9 (3,679)	0.4 (118)	13.5 (3,561)
Total	**20.5 (5,422)**	**3.2 (844)**	**17.3 (4,578)**

Heat and Mass Balance Diagrams

Heat and mass balance diagrams are shown for the following subsystems in Exhibit 3-39 through Exhibit 3-43:

- Coal gasification and air separation unit
- Syngas cleanup
- Sulfur recovery and tail gas recycle
- Combined cycle power generation
- Steam and feedwater

An overall plant energy balance is presented in tabular form in Exhibit 3-44. The power out is the combined combustion turbine, steam turbine and expander power prior to generator losses. The power at the generator terminals (shown in Exhibit 3-34) is calculated by multiplying the power out by a combined generator efficiency of 98.3 percent.

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Exhibit 3-39 Case 2 Coal Gasification and Air Separation Units Heat and Mass Balance Schematic

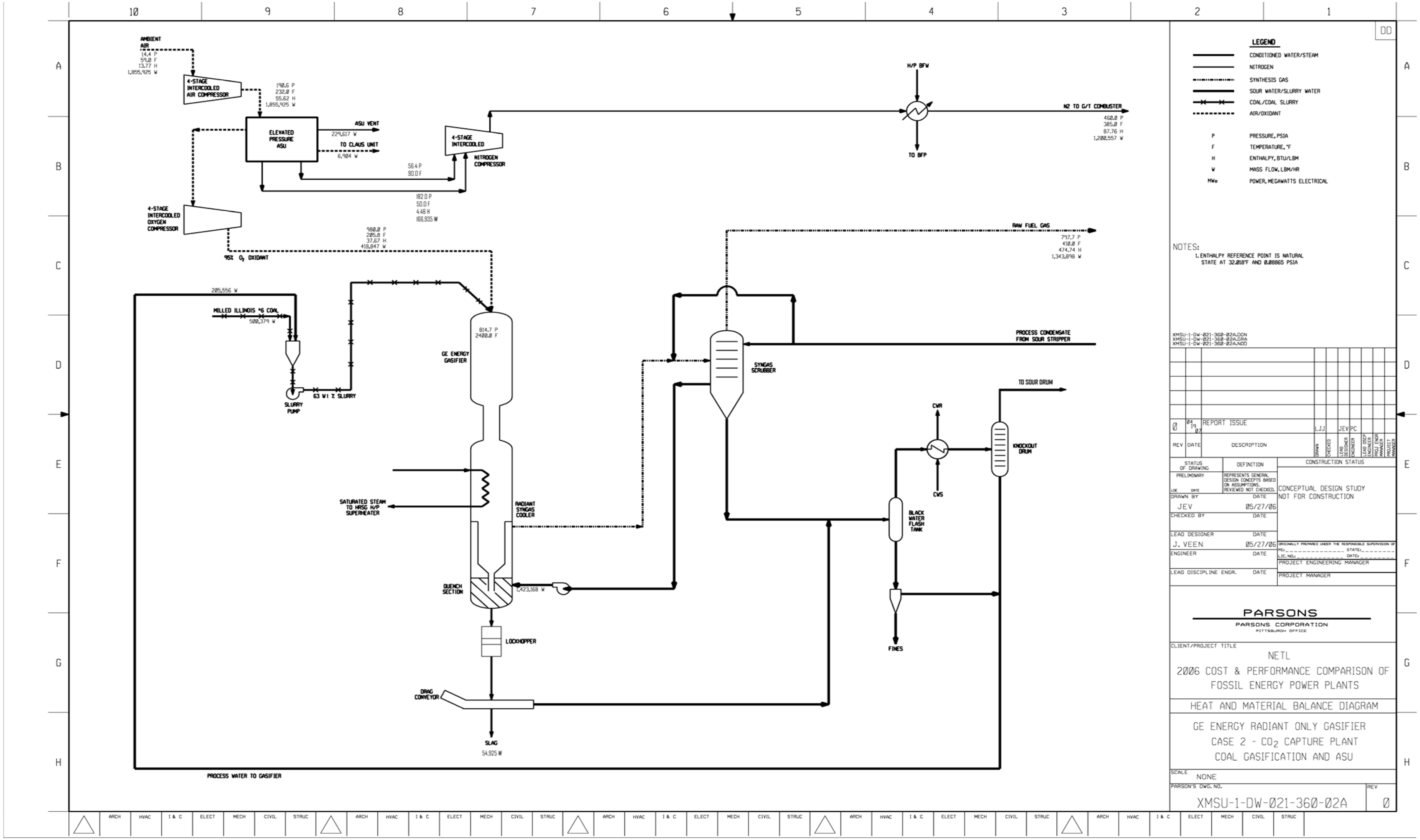

Exhibit 3-40 Case 2 Syngas Cleanup Heat and Mass Balance Schematic

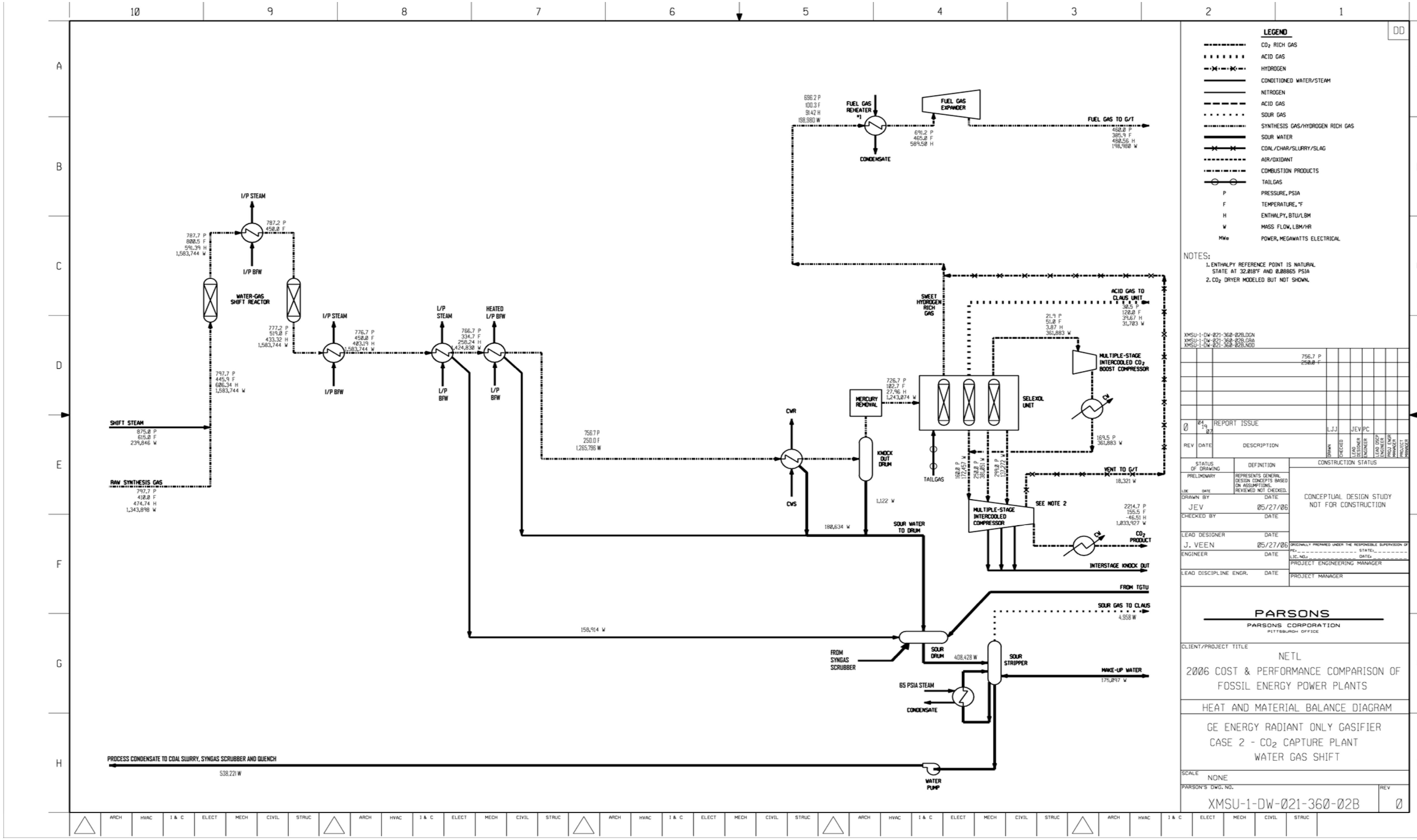

Exhibit 3-41 Case 2 Sulfur Recovery and Tail Gas Recycle Heat and Mass Balance Schematic

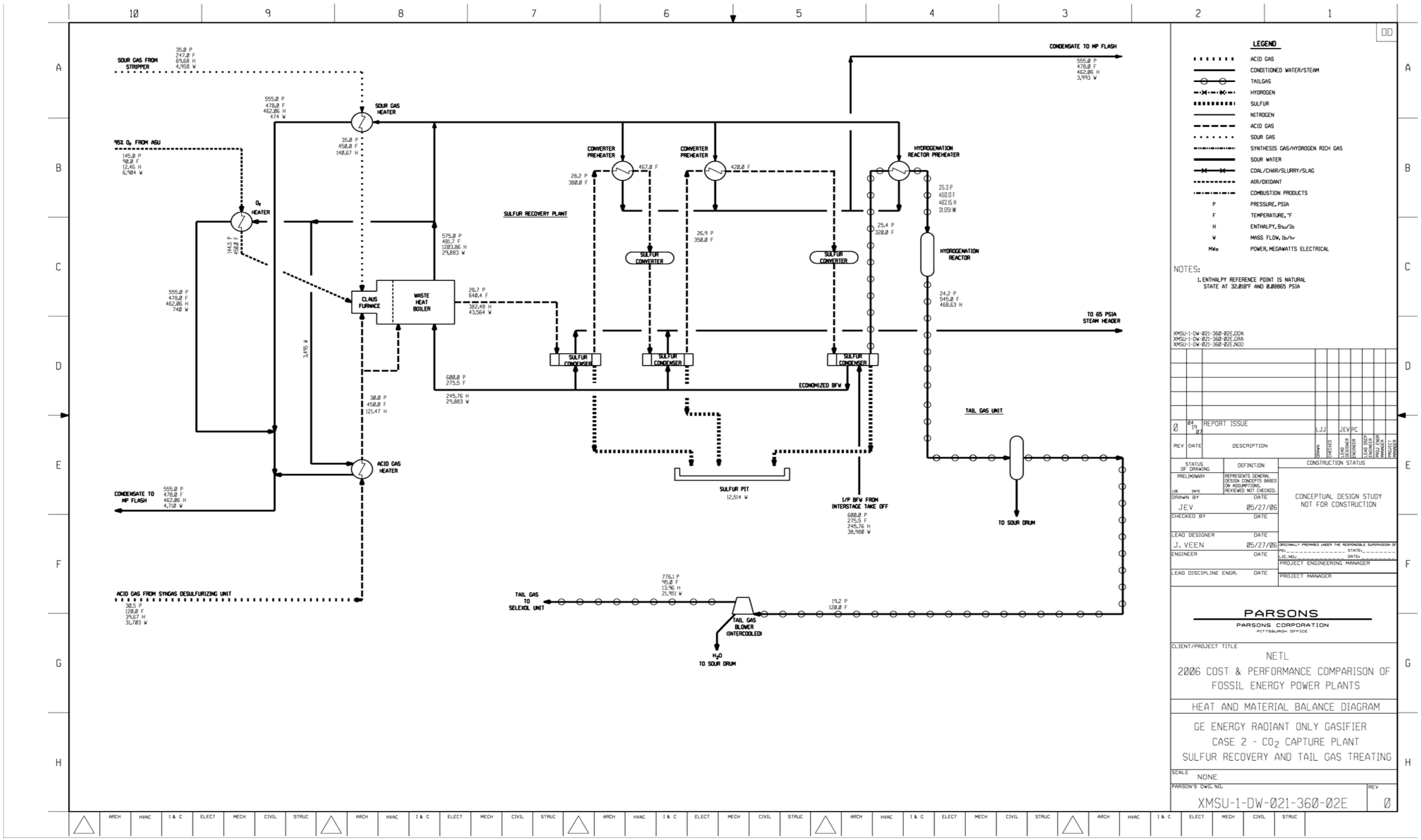

Exhibit 3-42 Case 2 Combined-Cycle Power Generation Heat and Mass Balance Schematic

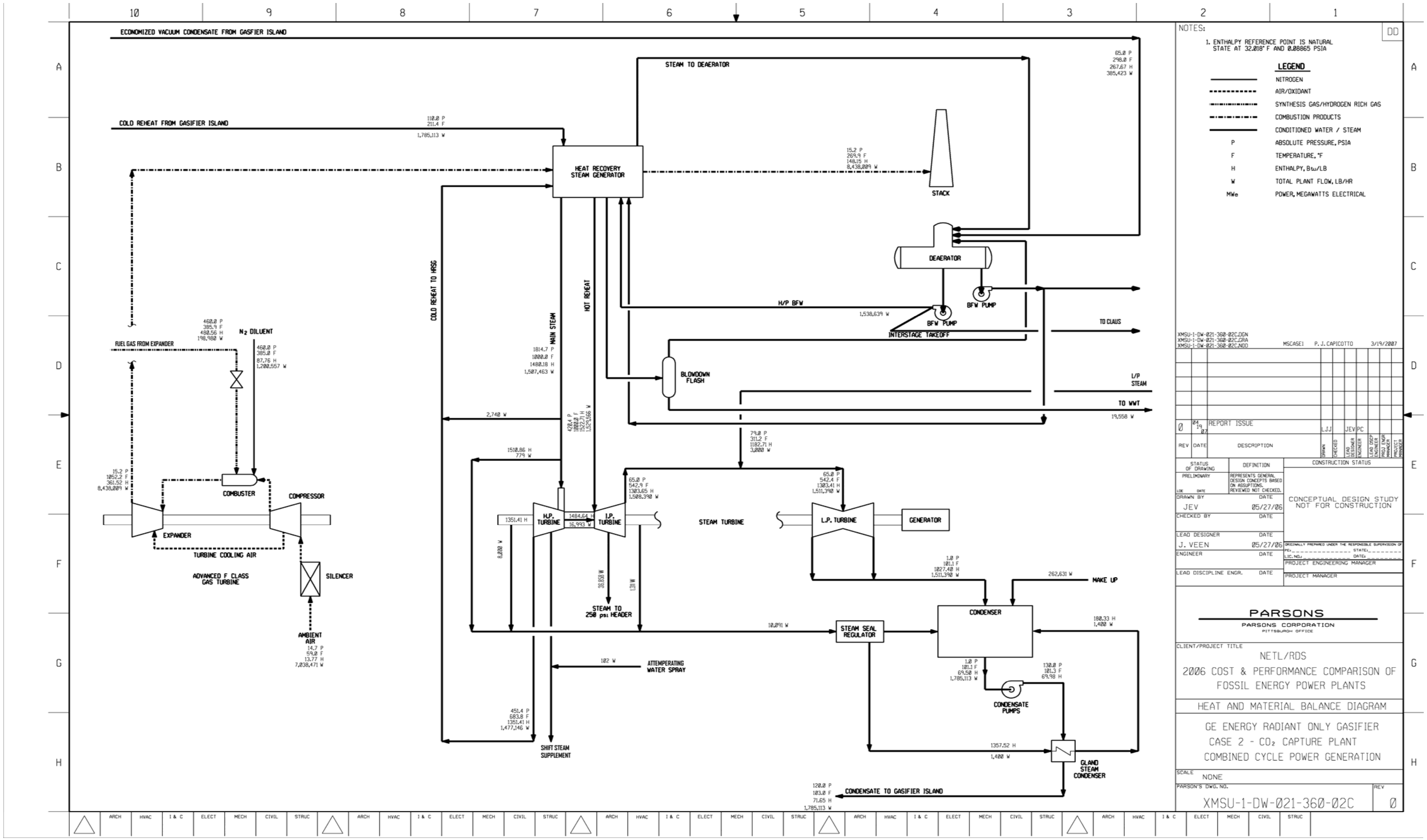

Exhibit 3-43 Case 2 Steam and Feedwater Heat and Mass Balance Schematic

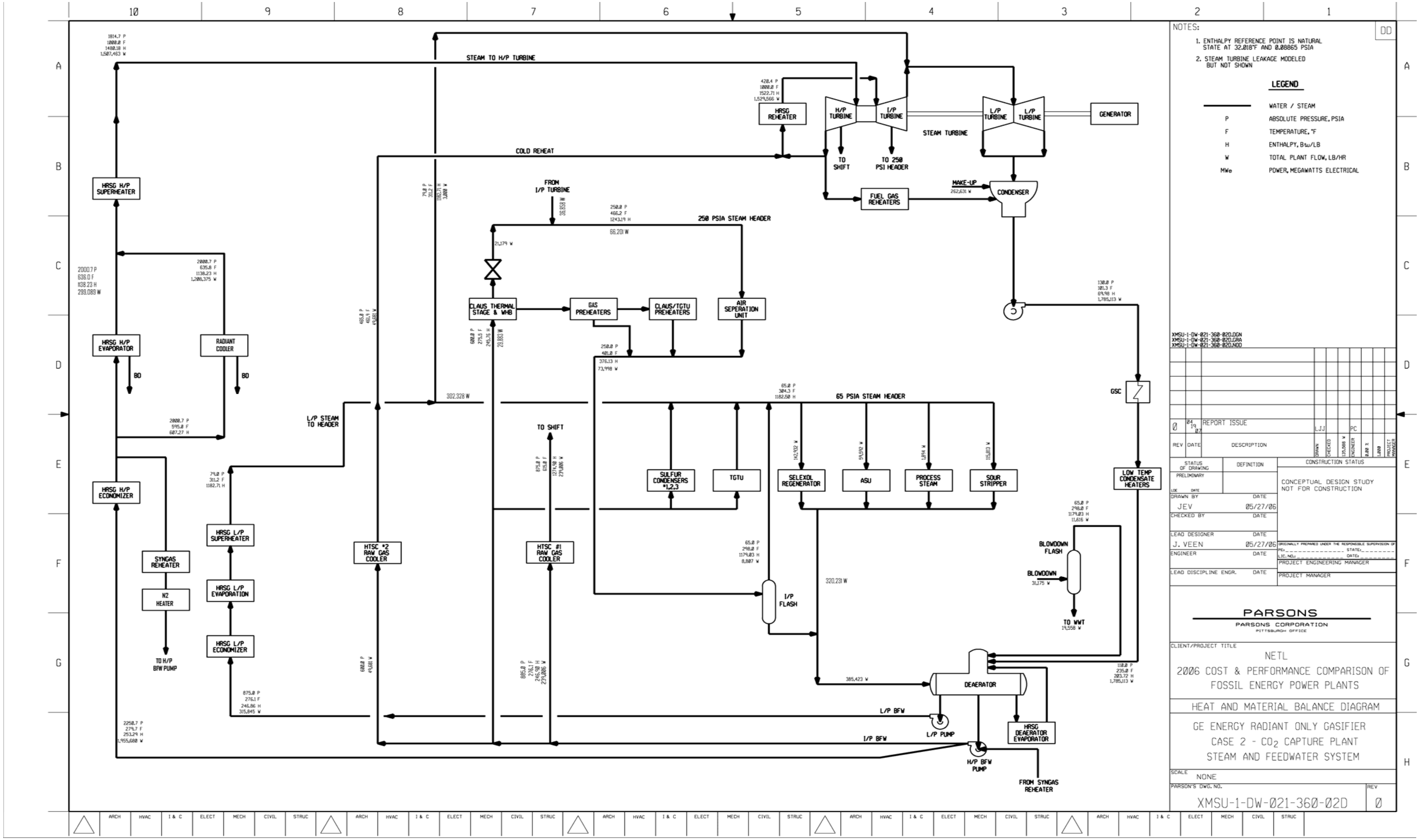

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Exhibit 3-44 Case 2 Overall Energy Balance (0°C [32°F] Reference)

	HHV	Sensible + Latent	Power	Total
Heat In (MMBtu/hr)				
Coal	5,837.4	4.9		5,842.3
ASU Air		25.6		25.6
CT Air		96.9		96.9
Water		13.3		13.3
Auxiliary Power			646.0	646.0
Totals	**5,837.4**	**140.7**	**646.0**	**6,624.1**
Heat Out (MMBtu/hr)				
ASU Intercoolers		269.0		269.0
ASU Vent		4.1		4.1
Slag	90.2	3.7		93.9
Sulfur	49.8	(1.2)		48.6
Tail Gas Compressor Intercoolers		3.5		3.5
CO_2 Compressor Intercoolers		138.0		138.0
CO_2 Product		(48.1)		(48.1)
HRSG Flue Gas		1,250.1		1,250.1
Condenser		1,431.0		1,431.0
Process Losses		847.4		847.4
Power			2,586.5	2,586.5
Totals	**140.0**	**3,897.5**	**2,586.5**	**6,624.1**

(1) Process Losses are calculated by difference and reflect various gasification, turbine, HRSG and other heat and work losses. Aspen flowsheet balance is within 0.5 percent.

3.2.10 CASE 2 - MAJOR EQUIPMENT LIST

Major equipment items for the GEE gasifier with CO_2 capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 3.2.11. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

ACCOUNT 1 COAL HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	181 tonne (200 ton)	2	0
2	Feeder	Belt	572 tonne/h (630 tph)	2	0
3	Conveyor No. 1	Belt	1,134 tonne/h (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,134 tonne/h (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,134 tonne/h (1,250 tph)	1	0
8	Reclaim Hopper	N/A	45 tonne (50 ton)	2	1
9	Feeder	Vibratory	191 tonne/h (210 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	372 tonne/h (410 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	191 tonne (210 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3" x 0 - 1-1/4" x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	372 tonne/h (410 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	372 tonne/h (410 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	816 tonne (900 ton)	3	0

ACCOUNT 2 COAL PREPARATION AND FEED

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	82 tonne/h (90 tph)	3	0
2	Conveyor No. 6	Belt w/tripper	254 tonne/h (280 tph)	1	0
3	Rod Mill Feed Hopper	Dual Outlet	499 tonne (550 ton)	1	0
4	Weigh Feeder	Belt	127 tonne/h (140 tph)	2	0
5	Rod Mill	Rotary	127 tonne/h (140 tph)	2	0
6	Slurry Water Storage Tank with Agitator	Field erected	306,621 liters (81,000 gal)	2	0
7	Slurry Water Pumps	Centrifugal	871 lpm (230 gpm)	2	2
10	Trommel Screen	Coarse	172 tonne/h (190 tph)	2	0
11	Rod Mill Discharge Tank with Agitator	Field erected	327,441 liters (86,500 gal)	2	0
12	Rod Mill Product Pumps	Centrifugal	2,726 lpm (720 gpm)	2	2
13	Slurry Storage Tank with Agitator	Field erected	984,215 liters (260,000 gal)	2	0
14	Slurry Recycle Pumps	Centrifugal	5,451 lpm (1,440 gpm)	2	2
15	Slurry Product Pumps	Positive displacement	2,726 lpm (720 gpm)	2	2

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	1,037,211 liters (274,000 gal)	3	0
2	Condensate Pumps	Vertical canned	7,457 lpm @ 91 m H2O (1,970 gpm @ 300 ft H2O)	2	1
3	Deaerator (integral w/ HRSG)	Horizontal spray type	544,311 kg/h (1,200,000 lb/h)	2	0
4	Intermediate Pressure Feedwater Pump	Horizontal centrifugal, single stage	1,363 lpm @ 707 m H2O (360 gpm @ 2320 ft H2O)	2	1
5	High Pressure Feedwater Pump No. 1	Barrel type, multi-stage, centrifugal	HP water: 6,662 lpm @ 1,890 m H2O (1,760 gpm @ 6,200 ft H2O)	2	1
6	High Pressure Feedwater Pump No. 2	Barrel type, multi-stage, centrifugal	IP water: 1,817 lpm @ 223 m H2O (480 gpm @ 730 ft H2O)	2	1
7	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/h, 2.8 MPa, 343°C (40,000 lb/h, 400 psig, 650°F)	1	0
8	Service Air Compressors	Flooded Screw	28 m3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
9	Instrument Air Dryers	Duplex, regenerative	28 m3/min (1,000 scfm)	2	1
10	Closed Cylce Cooling Heat Exchangers	Plate and frame	58 MMkJ/h (55 MMBtu/h) each	2	0
11	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,820 lpm @ 21 m H2O (5,500 gpm @ 70 ft H2O)	2	1
12	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H2O (1,000 gpm @ 290 ft H2O)	1	1
13	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H2O (700 gpm @ 210 ft H2O)	1	1
14	Raw Water Pumps	Stainless steel, single suction	9,615 lpm @ 18 m H2O (2,540 gpm @ 60 ft H2O)	2	1
15	Filtered Water Pumps	Stainless steel, single suction	3,710 lpm @ 49 m H2O (980 gpm @ 160 ft H2O)	2	1
16	Filtered Water Tank	Vertical, cylindrical	1,786,728 liter (472,000 gal)	2	0
17	Makeup Water Demineralizer	Anion, cation, and mixed bed	1,173 lpm (310 gpm)	2	0
18	Liquid Waste Treatment System		10 years, 24-hour storm	1	0

ACCOUNT 4 GASIFIER, ASU AND ACCESSORIES INCLUDING LOW TEMPERATURE HEAT RECOVERY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gasifier	Pressurized slurry-feed, entrained bed	2,994 tonne/day, 5.6 MPa (3,300 tpd, 815 psia)	2	0
2	Synthesis Gas Cooler	Vertical downflow radiant heat exchanger with outlet quench chamber	280,774 kg/h (619,000 lb/h)	2	0
3	Syngas Scrubber Including Sour Water Stripper	Vertical upflow	335,205 kg/h (739,000 lb/h)	2	0
4	Raw Gas Coolers	Shell and tube with condensate drain	395,079 kg/h (871,000 lb/h)	6	0
5	Raw Gas Knockout Drum	Vertical with mist eliminator	297,103 kg/h, 38°C, 5.2 MPa (655,000 lb/h, 100°F, 747 psia)	2	0
6	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	335,205 kg/h (739,000 lb/h) syngas	2	0
7	ASU Main Air Compressor	Centrifugal, multi-stage	6,343 m3/min @ 1.3 MPa (224,000 scfm @ 190 psia)	2	0
8	Cold Box	Vendor design	2,540 tonne/day (2,800 tpd) of 95% purity oxygen	2	0
9	Oxygen Compressor	Centrifugal, multi-stage	1,274 m3/min @ 7.1 MPa (45,000 scfm @ 1,030 psia)	2	0
10	Nitrogen Compressor	Centrifugal, multi-stage	3,625 m3/min @ 3.4 MPa (128,000 scfm @ 490 psia)	2	0
11	Nitrogen Boost Compressor	Centrifugal, multi-stage	595 m3/min @ 2.3 MPa (21,000 scfm @ 340 psia)	2	0

ACCOUNT 5A SOUR GAS SHIFT AND SYNGAS CLEANUP

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Mercury Adsorber	Sulfated carbon bed	310,258 kg/h (684,000 lb/h) 39°C (103°F) 5.1 MPa (737 psia)	2	0
2	Sulfur Plant	Claus type	150 tonne/day (165 tpd)	1	0
3	Water Gas Shift Reactors	Fixed bed, catalytic	395,079 kg/h (871,000 lb/h) 232°C (450°F) 5.5 MPa (798 psia)	4	0
4	Shift Reactor Heat Recovery Exhchangers	Shell and Tube	Exchanger 1: 148 MMkJ/h (140 MMBtu/h) Exchanger 2: 32 MMkJ/h (30 MMBtu/h)	4	0
5	Acid Gas Removal Plant	Two-stage Selexol	310,258 kg/h (684,000 lb/h) 39°C (103°F) 5.0 MPa (727 psia)	2	0
6	Hydrogenation Reactor	Fixed bed, catalytic	15,513 kg/h (34,200 lb/h) 232°C (450°F) 0.2 MPa (25 psia)	1	0
7	Tail Gas Recycle Compressor	Centrifugal	11,431 kg/h @ 6.4 MPa (25,200 lb/h @ 930 psi)	1	0

ACCOUNT 5B CO_2 COMPRESSION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CO2 Compressor	Integrally geared, multi-stage centrifugal	1,157 m3/min @ 15.3 MPa (40,859 scfm @ 2,215 psia)	4	1

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gas Turbine	Advanced F class	232 MW	2	0
2	Gas Turbine Generator	TEWAC	260 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	2	0
3	Syngas Expansion Turbine/Generator	Turbo expander	49,641 kg/h (109,440 lb/h) 4.8 MPa (691 psia) Inlet 3.2 MPa (460 psia) Outlet	2	0

ACCOUNT 7 HRSG, DUCTING, AND STACK

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	CS plate, type 409SS liner	76 m (250 ft) high x 8.5 m (28 ft) diameter	1	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	Main steam - 376,049 kg/h, 12.4 MPa/538°C (829,045 lb/h, 1,800 psig/1,000°F) Reheat steam - 381,590 kg/h, 2.9 MPa/538°C (841,261 lb/h, 420 psig/1,000°F)	2	0

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	298 MW 12.4 MPa/538°C/538°C (1800 psig/ 1000°F/1000°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitiation	330 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Steam Bypass	One per HRSG	50% steam flow @ design steam conditions	2	0
4	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,676 MMkJ/h (1,590 MMBtu/h) heat duty, Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1	0

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	359,617 lpm @ 30 m (95,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT 2,003 MMkJ/h (1,900 MMBtu/h) heat duty	1	0

ACCOUNT 10 SLAG RECOVERY AND HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Slag Quench Tank	Water bath	261,195 liters (69,000 gal)	2	0
2	Slag Crusher	Roll	14 tonne/h (15 tph)	2	0
3	Slag Depressurizer	Lock Hopper	14 tonne/h (15 tph)	2	0
4	Slag Receiving Tank	Horizontal, weir	170,345 liters (45,000 gal)	2	0
5	Black Water Overflow Tank	Shop fabricated	79,494 liters (21,000 gal)	2	0
6	Slag Conveyor	Drag chain	14 tonne/h (15 tph)	2	0
7	Slag Separation Screen	Vibrating	14 tonne/h (15 tph)	2	0
8	Coarse Slag Conveyor	Belt/bucket	14 tonne/h (15 tph)	2	0
9	Fine Ash Settling Tank	Vertical, gravity	253,625 liters (67,000 gal)	2	0
10	Fine Ash Recycle Pumps	Horizontal centrifugal	76 lpm @ 14 m H2O (20 gpm @ 46 ft H2O)	2	2
11	Grey Water Storage Tank	Field erected	83,280 liters (22,000 gal)	2	0
12	Grey Water Pumps	Centrifugal	303 lpm @ 564 m H2O (80 gpm @ 1,850 ft H2O)	2	2
13	Slag Storage Bin	Vertical, field erected	998 tonne (1,100 tons)	2	0
14	Unloading Equipment	Telescoping chute	118 tonne/h (130 tph)	1	0

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	24 kV/345 kV, 260 MVA, 3-ph, 60 Hz	2	0
2	STG Transformer	Oil-filled	24 kV/345 kV, 110 MVA, 3-ph, 60 Hz	1	0
3	Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 207 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 31 MVA, 3-ph, 60 Hz	1	1
5	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	2	0
6	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
7	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
8	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
9	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

ACCOUNT 12 INSTRUMENTATION AND CONTROL

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

3.2.11 CASE 2 - COST ESTIMATING

The cost estimating methodology was described previously in Section 2.6. Exhibit 3-45 shows the total plant cost summary organized by cost account and Exhibit 3-46 shows a more detailed breakdown of the capital costs. Exhibit 3-47 shows the initial and annual O&M costs.

The estimated TPC of the GEE gasifier with CO_2 capture is $2,390/kW. Process contingency represents 4.2 percent of the TPC and project contingency represents 13.6 percent. The 20-year LCOE, including CO_2 TS&M costs of 3.9 mills/kWh, is 102.9 mills/kWh.

Exhibit 3-45 Case 2 Total Plant Cost Summary

Client:	USDOE/NETL			**Report Date:**	05-Apr-07
Project:	Bituminous Baseline Study				
	TOTAL PLANT COST SUMMARY				
Case:	Case 02 - GEE Radiant Only IGCC w/ CO2				
Plant Size:	555.7 MW,net	**Estimate Type:**	Conceptual	**Cost Base (Dec)**	2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	$13,688	$2,552	$10,726	$0	$0	**$26,966**	$2,443	$0	$5,882	**$35,291**	$64
2	COAL & SORBENT PREP & FEED	$23,455	$4,274	$14,205	$0	$0	**$41,934**	$3,803	$1,522	$9,452	**$56,712**	$102
3	FEEDWATER & MISC. BOP SYSTEMS	$10,144	$8,686	$9,657	$0	$0	**$28,487**	$2,661	$0	$7,040	**$38,188**	$69
4	GASIFIER & ACCESSORIES											
4.1	Syngas Cooler Gasifier System	$103,362	$0	$57,380	$0	$0	**$160,742**	$14,715	$22,192	$30,349	**$227,999**	$410
4.2	Syngas Cooler(w/ Gasifier - 4.1)	w/4.1	$0	w/4.1	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.3	ASU/Oxidant Compression	$157,723	$0	w/equip.	$0	$0	**$157,723**	$15,012	$0	$17,274	**$190,009**	$342
4.4-4.9	Other Gasification Equipment	$12,297	$11,735	$12,985	$0	$0	**$37,018**	$3,516	$0	$8,381	**$48,914**	$88
	SUBTOTAL 4	**$273,383**	**$11,735**	**$70,365**	**$0**	**$0**	**$355,484**	**$33,243**	**$22,192**	**$56,003**	**$466,922**	**$840**
5A	Gas Cleanup & Piping	$79,047	$4,945	$70,370	$0	$0	**$154,363**	$14,797	$22,231	$38,475	**$229,866**	$414
5B	CO_2 REMOVAL & COMPRESSION	$17,712	$0	$10,865	$0	$0	**$28,577**	$2,732	$0	$6,262	**$37,572**	$68
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$88,000	$0	$5,325	$0	$0	**$93,325**	$8,779	$9,332	$11,144	**$122,580**	$221
6.2-6.9	Combustion Turbine Other	$5,270	$752	$1,575	$0	$0	**$7,598**	$715	$0	$1,508	**$9,820**	$18
	SUBTOTAL 6	**$93,270**	**$752**	**$6,900**	**$0**	**$0**	**$100,922**	**$9,494**	**$9,332**	**$12,651**	**$132,400**	**$238**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$32,193	$0	$4,581	$0	$0	**$36,774**	$3,471	$0	$4,025	**$44,270**	$80
7.2-7.9	Ductwork and Stack	$3,222	$2,268	$3,011	$0	$0	**$8,501**	$785	$0	$1,510	**$10,795**	$19
	SUBTOTAL 7	**$35,415**	**$2,268**	**$7,592**	**$0**	**$0**	**$45,275**	**$4,256**	**$0**	**$5,534**	**$55,065**	**$99**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$28,444	$0	$4,847	$0	$0	**$33,291**	$3,190	$0	$3,648	**$40,130**	$72
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$10,439	$943	$7,306	$0	$0	**$18,688**	$1,684	$0	$4,109	**$24,481**	$44
	SUBTOTAL 8	**$38,883**	**$943**	**$12,153**	**$0**	**$0**	**$51,979**	**$4,875**	**$0**	**$7,757**	**$64,611**	**$116**
9	COOLING WATER SYSTEM	$7,074	$7,437	$6,229	$0	$0	**$20,740**	$1,905	$0	$4,628	**$27,273**	$49
10	ASH/SPENT SORBENT HANDLING SYS	$14,265	$7,973	$14,470	$0	$0	**$36,708**	$3,509	$0	$4,331	**$44,548**	$80
11	ACCESSORY ELECTRIC PLANT	$23,997	$11,838	$23,440	$0	$0	**$59,275**	$5,162	$0	$12,496	**$76,933**	$138
12	INSTRUMENTATION & CONTROL	$10,469	$1,960	$7,028	$0	$0	**$19,457**	$1,793	$973	$3,718	**$25,942**	$47
13	IMPROVEMENTS TO SITE	$3,318	$1,956	$8,248	$0	$0	**$13,522**	$1,328	$0	$4,455	**$19,305**	$35
14	BUILDINGS & STRUCTURES	$0	$6,410	$7,441	$0	$0	**$13,851**	$1,259	$0	$2,474	**$17,583**	$32
	TOTAL COST	**$644,121**	**$73,729**	**$279,690**	**$0**	**$0**	**$997,540**	**$93,261**	**$56,251**	**$181,157**	**$1,328,209**	**$2,390**

Exhibit 3-46 Case 2 Total Plant Cost Details

Client: USDOE/NETL **Report Date:** 05-Apr-07

Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 02 - GEE Radiant Only IGCC w/ CO2

Plant Size: 555.7 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	$3,595	$0	$1,775	$0	$0	$5,370	$481	$0	$1,170	$7,020	$13
1.2	Coal Stackout & Reclaim	$4,645	$0	$1,138	$0	$0	$5,783	$507	$0	$1,258	$7,548	$14
1.3	Coal Conveyors	$4,319	$0	$1,126	$0	$0	$5,445	$478	$0	$1,185	$7,107	$13
1.4	Other Coal Handling	$1,130	$0	$260	$0	$0	$1,390	$122	$0	$302	$1,815	$3
1.5	Sorbent Receive & Unload	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.6	Sorbent Stackout & Reclaim	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.7	Sorbent Conveyors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.8	Other Sorbent Handling	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.9	Coal & Sorbent Hnd.Foundations	$0	$2,552	$6,427	$0	$0	$8,979	$856	$0	$1,967	$11,801	$21
	SUBTOTAL 1.	**$13,688**	**$2,552**	**$10,726**	**$0**	**$0**	**$26,966**	**$2,443**	**$0**	**$5,882**	**$35,291**	**$64**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying incl w/2.3	incl. w/ 2.3	incl. w/ 2.3	incl. w/ 2.3	$0	$0	$0	$0	$0	$0	$0	$0
2.2	Prepared Coal Storage & Feed	$1,537	$366	$244	$0	$0	$2,146	$184	$0	$466	$2,796	$5
2.3	Slurry Prep & Feed	$21,073	$0	$9,373	$0	$0	$30,446	$2,760	$1,522	$6,946	$41,674	$75
2.4	Misc.Coal Prep & Feed	$845	$612	$1,863	$0	$0	$3,320	$304	$0	$725	$4,350	$8
2.5	Sorbent Prep Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.6	Sorbent Storage & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.7	Sorbent Injection System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.8	Booster Air Supply System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.9	Coal & Sorbent Feed Foundation	$0	$3,296	$2,725	$0	$0	$6,021	$555	$0	$1,315	$7,892	$14
	SUBTOTAL 2.	**$23,455**	**$4,274**	**$14,205**	**$0**	**$0**	**$41,934**	**$3,803**	**$1,522**	**$9,452**	**$56,712**	**$102**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	$3,396	$5,905	$3,119	$0	$0	$12,420	$1,146	$0	$2,713	$16,280	$29
3.2	Water Makeup & Pretreating	$577	$60	$322	$0	$0	$960	$91	$0	$315	$1,365	$2
3.3	Other Feedwater Subsystems	$1,875	$636	$573	$0	$0	$3,084	$276	$0	$672	$4,031	$7
3.4	Service Water Systems	$333	$679	$2,358	$0	$0	$3,370	$326	$0	$1,109	$4,805	$9
3.5	Other Boiler Plant Systems	$1,787	$686	$1,701	$0	$0	$4,173	$391	$0	$913	$5,478	$10
3.6	FO Supply Sys & Nat Gas	$306	$577	$539	$0	$0	$1,421	$136	$0	$311	$1,868	$3
3.7	Waste Treatment Equipment	$802	$0	$492	$0	$0	$1,294	$125	$0	$426	$1,845	$3
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	$1,068	$144	$553	$0	$0	$1,765	$170	$0	$581	$2,516	$5
	SUBTOTAL 3.	**$10,144**	**$8,686**	**$9,657**	**$0**	**$0**	**$28,487**	**$2,661**	**$0**	**$7,040**	**$38,188**	**$69**
4	GASIFIER & ACCESSORIES											
4.1	Syngas Cooler Gasifier System	$103,362	$0	$57,380	$0	$0	$160,742	$14,715	$22,192	$30,349	$227,999	$410
4.2	Syngas Cooler(w/ Gasifier - 4.1)	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.3	ASU/Oxidant Compression	$157,723	$0	w/equip.	$0	$0	$157,723	$15,012	$0	$17,274	$190,009	$342
4.4	Scrubber & Low Temperature Cooling	$9,391	$7,629	$7,963	$0	$0	$24,983	$2,381	$0	$5,473	$32,838	$59
4.5	Black Water & Sour Gas Section	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.6	Other Gasification Equipment	$2,907	$1,380	$2,730	$0	$0	$7,017	$671	$0	$1,538	$9,226	$17
4.8	Major Component Rigging	$0	w/4.1	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.9	Gasification Foundations	$0	$2,726	$2,292	$0	$0	$5,018	$463	$0	$1,370	$6,851	$12
	SUBTOTAL 4.	**$273,383**	**$11,735**	**$70,365**	**$0**	**$0**	**$355,484**	**$33,243**	**$22,192**	**$56,003**	**$466,922**	**$840**

Exhibit 3-46 Case 2 Total Plant Cost Details (Continued)

Client: USDOE/NETL **Report Date:** 05-Apr-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 02 - GEE Radiant Only IGCC w/ CO2
Plant Size: 555.7 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5A	GAS CLEANUP & PIPING											
5A.1	Double Stage Selexol	$59,515	$0	$51,050	$0	$0	$110,564	$10,614	$22,113	$28,658	$171,950	$309
5A.2	Elemental Sulfur Plant	$10,010	$1,987	$12,925	$0	$0	$24,922	$2,403	$0	$5,465	$32,790	$59
5A.3	Mercury Removal	$1,340	$0	$1,020	$0	$0	$2,360	$226	$118	$541	$3,245	$6
5A.4	Shift Reactors	$8,183	$0	$3,380	$0	$0	$11,563	$1,101	$0	$2,533	$15,196	$27
5A.5	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.6	Blowback Gas Systems	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.7	Fuel Gas Piping	$0	$1,862	$1,283	$0	$0	$3,146	$287	$0	$686	$4,119	$7
5A.9	HGCU Foundations	$0	$1,096	$712	$0	$0	$1,808	$166	$0	$592	$2,565	$5
	SUBTOTAL 5A.	**$79,047**	**$4,945**	**$70,370**	**$0**	**$0**	**$154,363**	**$14,797**	**$22,231**	**$38,475**	**$229,866**	**$414**
5B	CO2 REMOVAL & COMPRESSION											
5B.1	CO2 Removal System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5B.2	CO2 Compression & Drying	$17,712	$0	$10,865	$0	$0	$28,577	$2,732	$0	$6,262	$37,572	$68
	SUBTOTAL 5B.	**$17,712**	**$0**	**$10,865**	**$0**	**$0**	**$28,577**	**$2,732**	**$0**	**$6,262**	**$37,572**	**$68**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$88,000	$0	$5,325	$0	$0	$93,325	$8,779	$9,332	$11,144	$122,580	$221
6.2	Syngas Expander	$5,270	$0	$737	$0	$0	$6,007	$567	$0	$986	$7,560	$14
6.3	Compressed Air Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.9	Combustion Turbine Foundations	$0	$752	$838	$0	$0	$1,591	$148	$0	$522	$2,260	$4
	SUBTOTAL 6.	**$93,270**	**$752**	**$6,900**	**$0**	**$0**	**$100,922**	**$9,494**	**$9,332**	**$12,651**	**$132,400**	**$238**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$32,193	$0	$4,581	$0	$0	$36,774	$3,471	$0	$4,025	$44,270	$80
7.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$0	$1,627	$1,179	$0	$0	$2,806	$246	$0	$610	$3,663	$7
7.4	Stack	$3,222	$0	$1,211	$0	$0	$4,433	$422	$0	$485	$5,340	$10
7.9	HRSG,Duct & Stack Foundations	$0	$641	$620	$0	$0	$1,262	$117	$0	$414	$1,792	$3
	SUBTOTAL 7.	**$35,415**	**$2,268**	**$7,592**	**$0**	**$0**	**$45,275**	**$4,256**	**$0**	**$5,534**	**$55,065**	**$99**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$28,444	$0	$4,847	$0	$0	$33,291	$3,190	$0	$3,648	$40,130	$72
8.2	Turbine Plant Auxiliaries	$195	$0	$449	$0	$0	$645	$63	$0	$71	$778	$1
8.3	Condenser & Auxiliaries	$4,788	$0	$1,407	$0	$0	$6,195	$588	$0	$678	$7,461	$13
8.4	Steam Piping	$5,455	$0	$3,844	$0	$0	$9,299	$793	$0	$2,523	$12,616	$23
8.9	TG Foundations	$0	$943	$1,605	$0	$0	$2,548	$240	$0	$837	$3,625	$7
	SUBTOTAL 8.	**$38,883**	**$943**	**$12,153**	**$0**	**$0**	**$51,979**	**$4,875**	**$0**	**$7,757**	**$64,611**	**$116**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$4,602	$0	$1,012	$0	$0	$5,614	$531	$0	$922	$7,067	$13
9.2	Circulating Water Pumps	$1,448	$0	$92	$0	$0	$1,540	$132	$0	$251	$1,923	$3
9.3	Circ.Water System Auxiliaries	$119	$0	$17	$0	$0	$136	$13	$0	$22	$172	$0
9.4	Circ.Water Piping	$0	$5,063	$1,292	$0	$0	$6,354	$563	$0	$1,383	$8,300	$15
9.5	Make-up Water System	$320	$0	$454	$0	$0	$774	$73	$0	$170	$1,017	$2
9.6	Component Cooling Water Sys	$584	$698	$493	$0	$0	$1,775	$164	$0	$388	$2,327	$4
9.9	Circ.Water System Foundations& Structures	$0	$1,676	$2,870	$0	$0	$4,546	$429	$0	$1,492	$6,467	$12
	SUBTOTAL 9.	**$7,074**	**$7,437**	**$6,229**	**$0**	**$0**	**$20,740**	**$1,905**	**$0**	**$4,628**	**$27,273**	**$49**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Slag Dewatering & Cooling	$11,749	$6,479	$13,172	$0	$0	$31,400	$3,008	$0	$3,441	$37,849	$68
10.2	Gasifier Ash Depressurization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.3	Cleanup Ash Depressurization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.4	High Temperature Ash Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.5	Other Ash Rrecovery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$569	$0	$619	$0	$0	$1,188	$114	$0	$195	$1,498	$3
10.7	Ash Transport & Feed Equipment	$768	$0	$184	$0	$0	$953	$88	$0	$156	$1,196	$2
10.8	Misc. Ash Handling Equipment	$1,178	$1,444	$432	$0	$0	$3,054	$289	$0	$501	$3,844	$7
10.9	Ash/Spent Sorbent Foundation	$0	$50	$63	$0	$0	$113	$11	$0	$37	$161	$0
	SUBTOTAL 10.	**$14,265**	**$7,973**	**$14,470**	**$0**	**$0**	**$36,708**	**$3,509**	**$0**	**$4,331**	**$44,548**	**$80**

Exhibit 3-46 Case 2 Total Plant Cost Details (Continued)

	Client:	USDOE/NETL								Report Date:	05-Apr-07		
	Project:	Bituminous Baseline Study											
		TOTAL PLANT COST SUMMARY											
	Case:	Case 02 - GEE Radiant Only IGCC w/ CO2											
	Plant Size:	555.7 MW,net		Estimate Type:		Conceptual				Cost Base (Dec)	2006	($x1000)	

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$903	$0	$900	$0	$0	$1,803	$171	$0	$197	$2,172	$4
11.2	Station Service Equipment	$4,284	$0	$402	$0	$0	$4,686	$445	$0	$513	$5,644	$10
11.3	Switchgear & Motor Control	$8,187	$0	$1,501	$0	$0	$9,687	$897	$0	$1,588	$12,172	$22
11.4	Conduit & Cable Tray	$0	$3,895	$12,645	$0	$0	$16,540	$1,581	$0	$4,530	$22,652	$41
11.5	Wire & Cable	$0	$7,154	$4,812	$0	$0	$11,966	$875	$0	$3,210	$16,050	$29
11.6	Protective Equipment	$0	$640	$2,427	$0	$0	$3,067	$300	$0	$505	$3,872	$7
11.7	Standby Equipment	$215	$0	$219	$0	$0	$434	$42	$0	$71	$547	$1
11.8	Main Power Transformers	$10,409	$0	$139	$0	$0	$10,548	$799	$0	$1,702	$13,048	$23
11.9	Electrical Foundations	$0	$149	$395	$0	$0	$544	$52	$0	$179	$775	$1
	SUBTOTAL 11.	**$23,997**	**$11,838**	**$23,440**	**$0**	**$0**	**$59,275**	**$5,162**	**$0**	**$12,496**	**$76,933**	**$138**
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
12.3	Steam Turbine Control	w/8.1	$0	w/8.1	$0	$0	$0	$0	$0	$0	$0	$0
12.4	Other Major Component Control	$1,034	$0	$719	$0	$0	$1,752	$169	$88	$301	$2,310	$4
12.5	Signal Processing Equipment	W/12.7	$0	W/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.6	Control Boards,Panels & Racks	$238	$0	$159	$0	$0	$396	$38	$20	$91	$545	$1
12.7	Computer & Accessories	$5,513	$0	$184	$0	$0	$5,697	$540	$285	$652	$7,174	$13
12.8	Instrument Wiring & Tubing	$0	$1,960	$4,102	$0	$0	$6,062	$514	$303	$1,720	$8,599	$15
12.9	Other I & C Equipment	$3,685	$0	$1,864	$0	$0	$5,550	$533	$277	$954	$7,314	$13
	SUBTOTAL 12.	**$10,469**	**$1,960**	**$7,028**	**$0**	**$0**	**$19,457**	**$1,793**	**$973**	**$3,718**	**$25,942**	**$47**
13	Improvements to Site											
13.1	Site Preparation	$0	$104	$2,242	$0	$0	$2,346	$231	$0	$773	$3,350	$6
13.2	Site Improvements	$0	$1,851	$2,479	$0	$0	$4,330	$425	$0	$1,427	$6,182	$11
13.3	Site Facilities	$3,318	$0	$3,527	$0	$0	$6,845	$672	$0	$2,255	$9,773	$18
	SUBTOTAL 13.	**$3,318**	**$1,956**	**$8,248**	**$0**	**$0**	**$13,522**	**$1,328**	**$0**	**$4,455**	**$19,305**	**$35**
14	Buildings & Structures											
14.1	Combustion Turbine Area	$0	$221	$127	$0	$0	$348	$31	$0	$76	$454	$1
14.2	Steam Turbine Building	$0	$2,290	$3,307	$0	$0	$5,597	$514	$0	$917	$7,028	$13
14.3	Administration Building	$0	$833	$612	$0	$0	$1,446	$129	$0	$236	$1,810	$3
14.4	Circulation Water Pumphouse	$0	$156	$84	$0	$0	$240	$21	$0	$39	$301	$1
14.5	Water Treatment Buildings	$0	$460	$454	$0	$0	$914	$82	$0	$149	$1,146	$2
14.6	Machine Shop	$0	$426	$296	$0	$0	$722	$64	$0	$118	$904	$2
14.7	Warehouse	$0	$688	$450	$0	$0	$1,139	$101	$0	$186	$1,426	$3
14.8	Other Buildings & Structures	$0	$412	$325	$0	$0	$738	$66	$0	$161	$964	$2
14.9	Waste Treating Building & Str.	$0	$922	$1,785	$0	$0	$2,707	$252	$0	$592	$3,550	$6
	SUBTOTAL 14.	**$0**	**$6,410**	**$7,441**	**$0**	**$0**	**$13,851**	**$1,259**	**$0**	**$2,474**	**$17,583**	**$32**
	TOTAL COST	**$644,121**	**$73,729**	**$279,690**	**$0**	**$0**	**$997,540**	**$93,261**	**$56,251**	**$181,157**	**$1,328,209**	**$2,390**

Exhibit 3-47 Case 2 Initial and Annual Operating and Maintenance Costs

INITIAL & ANNUAL O&M EXPENSES						Cost Base (Dec)	2006
Case 02 - GEE Radiant Only IGCC w/ CO2						Heat Rate-net(Btu/kWh):	10,505
						MWe-net:	556
						Capacity Factor: (%):	80
OPERATING & MAINTENANCE LABOR							
Operating Labor							
Operating Labor Rate(base):	33.00	$/hour					
Operating Labor Burden:	30.00	% of base					
Labor O-H Charge Rate:	25.00	% of labor					
			Total				
Skilled Operator	2.0		2.0				
Operator	10.0		10.0				
Foreman	1.0		1.0				
Lab Tech's, etc.	3.0		3.0				
TOTAL-O.J.'s	16.0		16.0				
						Annual Cost $	Annual Unit Cost $/kW-net
Annual Operating Labor Cost						$6,012,864	$10.820
Maintenance Labor Cost						$13,432,424	$24.172
Administrative & Support Labor						$4,861,322	$8.748
TOTAL FIXED OPERATING COSTS						**$24,306,610**	**$43.741**
VARIABLE OPERATING COSTS							
							$/kWh-net
Maintenance Material Cost						**$24,602,924**	**$0.00632**
Consumables	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost			
Water(/1000 gallons)	0	6,594	1.03	**$0**		**$1,983,139**	**$0.00051**
Chemicals							
MU & WT Chem.(lb)	137,493	19,642	0.16	$22,659		$945,198	$0.00024
Carbon (Mercury Removal) (lb)	84,811	116	1.00	$84,811		$33,872	$0.00001
COS Catalyst (m3)	0	0	2,308.40	$0		$0	$0.00000
Water Gas Shift Catalyst(ft3)	6,288	4.30	475.00	$2,986,800		$596,410	$0.00015
Selexol Solution (gal)	504	72	12.90	$6,502		$271,232	$0.00007
MDEA Solution (gal)	0	0	0.96	$0		$0	$0.00000
Sulfinol Solution (gal)	0	0	9.68	$0		$0	$0.00000
SCR Catalyst (m3)	0	0	0.00	$0		$0	$0.00000
Aqueous Ammonia (ton)	0	0	0.00	$0		$0	$0.00000
Claus Catalyst(ft3)	w/equip	2.25	125.00	$0		$82,125	$0.00002
Subtotal Chemicals				**$3,100,772**		**$1,928,837**	**$0.00050**
Other							
Supplemental Fuel(MBtu)	0	0	0.00	$0		$0	$0.00000
Gases,N2 etc.(/100scf)	0	0	0.00	$0		$0	$0.00000
L.P. Steam(/1000 pounds)	0	0	0.00	$0		$0	$0.00000
Subtotal Other				**$0**		**$0**	**$0.00000**
Waste Disposal							
Spent Mercury Catalyst (lb)	0	116	0.40	$0		$13,603	$0.00000
Flyash (ton)	0	0	0.00	$0		$0	$0.00000
Bottom Ash(ton)	0	659	15.45	$0		$2,973,464	$0.00076
Subtotal-Waste Disposal				**$0**		**$2,987,067**	**$0.00077**
By-products & Emissions	0	0	0.00			$0	$0.00000
Sulfur(tons)	0	150	0.00	$0		$0	$0.00000
Subtotal By-Products				**$0**		**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$3,100,772**		**$31,501,967**	**$0.00809**
Fuel(ton)	180,143	6,005	42.11	**$7,585,825**		**$73,835,368**	**$0.01896**

3.3 CONOCOPHILLIPS E-GAS™ IGCC CASES

This section contains an evaluation of plant designs for Cases 3 and 4, which are based on the ConocoPhillips (CoP) E-Gas™ gasifier. Cases 3 and 4 are very similar in terms of process, equipment, scope and arrangement, except that Case 4 includes sour gas shift reactors, CO_2 absorption/regeneration and compression/transport systems. There are no provisions for CO_2 removal in Case 3.

The balance of this section is organized in an analogous manner to Section 3.2:

- Gasifier Background
- Process System Description for Case 3
- Key Assumptions for Cases 3 and 4
- Sparing Philosophy for Cases 3 and 4
- Performance Results for Case 3
- Equipment List for Case 3
- Cost Estimates for Case 3
- Process and System Description, Performance Results, Equipment List and Cost Estimate for Case 4

3.3.1 GASIFIER BACKGROUND

Dow Chemical (the former principal stockholder of Destec Energy, which was bought by Global Energy, Inc., the gasifier business that was purchased by ConocoPhillips) is a major producer of chemicals. They began coal gasification development work in 1976 with bench-scale (2 kg/h [4 lb/h]) reactor testing. Important fundamental data were obtained for conversion and yields with various coals and operating conditions. This work led to the construction of a pilot plant at Dow's large chemical complex in Plaquemine, Louisiana. The pilot plant was designed for a capacity of 11 tonnes/day (12 TPD) (dry lignite basis) and was principally operated with air as the oxidant. The plant also operated with oxygen at an increased capacity of 33 tonnes/day (36 TPD) (dry lignite basis). This pilot plant operated from 1978 through 1983.

Following successful operation of the pilot plant, Dow built a larger 499 tonnes/day (550 TPD) (dry lignite basis) gasifier at Plaquemine. In 1984, Dow Chemical and the U.S. Synthetic Fuels Corporation (SFC) announced a price guarantee contract which allowed the building of the first commercial-scale Dow coal gasification unit. The Louisiana Gasification Technology, Inc. (LGTI) plant, sometimes called the Dow Syngas Project, was also located in the Dow Plaquemine chemical complex. The plant gasified about 1,451 tonnes/day (1,600 TPD) (dry basis) of subbituminous coal to generate 184 MW (gross) of combined-cycle electricity. To ensure continuous power output to the petrochemical complex, a minimum of 20 percent of natural gas was co-fired with the syngas. LGTI was operated from 1987 through 1995.

In September 1991, DOE selected the Wabash River coal gasification repowering project, which used the Destec Energy process, for funding under the Clean Coal Technology Demonstration Program. The project was a joint venture of Destec and Public Service of Indiana (PSI Energy, Inc.). Its purpose was to repower a unit at PSI's Wabash River station in West Terre Haute, Indiana to produce 265 MW of net power from local high-sulfur bituminous coal. The design of the project gasifier was based on the Destec LGTI gasifier. Experience gained in that project provided significant input to the design of the Wabash River coal gasification facility and eliminated much of the risk associated with scale-up and process variables.

Gasifier Capacity – The gasifier originally developed by Dow is now known as the CoP E-Gas™ gasifier. The daily coal-handling capacity of the E-Gas gasifier operating at Plaquemine was in the range of 1,270 tonnes (1,400 tons) (moisture/ash-free [MAF] basis) for bituminous coal to 1,497 tonnes (1,650 tons) for lignite. The dry gas production rate was 141,600 Nm^3/h (5 million scf/h) with an energy content of about 1,370 MMkJ/h (1,300 MMBtu/h) (HHV). The daily coal-handling capacity of the gasifier at Wabash River is about 1,678 tonnes (1,850 tons) (MAF basis) for high-sulfur bituminous coal. The dry gas production rate is about 189,724 Nm^3/h (6.7 million scf/h) with an energy content of about 1,950 MMkJ/h (1,850 MMBtu/h) (HHV). This size matches the combustion turbine, which is a GE 7FA.

With increased power and fuel gas turbine demand, the gasifier coal feed increases proportionately. CoP has indicated that the gasifier can readily handle the increased demand.

Distinguishing Characteristics - A key advantage of the CoP coal gasification technology is the current operating experience with subbituminous coal at full commercial scale at the Plaquemine plant and bituminous coal at the Wabash plant. The two-stage operation improves the efficiency, reduces oxygen requirements, and enables more effective operation on slurry feeds relative to a single stage gasifier. The fire-tube SGC used by E-Gas has a lower capital cost than a water-tube design, an added advantage for the CoP technology at this time. However, this experience may spur other developers to try fire-tube designs.

Entrained-flow gasifiers have fundamental environmental advantages over fluidized-bed and moving-bed gasifiers. They produce no hydrocarbon liquids, and the only solid waste is an inert slag.

The key disadvantages of the CoP coal gasification technology are the relatively short refractory life and the high waste heat recovery (SGC) duty. As with the other entrained-flow slagging gasifiers, these disadvantages result from high operating temperature. However, the two-stage operation results in a quenched syngas that is higher in CH_4 content than other gasifiers. This becomes a disadvantage in CO_2 capture cases since the CH_4 passes through the SGS reactors without change, and is also not separated by the AGR thus limiting the amount of carbon that can be captured.

Important Coal Characteristics - The slurry feeding system and the recycle of process condensate water as the principal slurrying liquid make low levels of ash and soluble salts desirable coal characteristics for use in the E-Gas™ coal gasification process. High ash levels increase the ratio of water to carbon in the coal in the feed slurry, thereby increasing the oxygen requirements. Soluble salts affect the processing cost and amount of water blowdown required to avoid problems associated with excessive buildup of salts in the slurry water recycle loop.

Bituminous coals with lower inherent moisture improve the slurry concentration and reduce oxygen requirements. The two-stage operation reduces the negative impact of low-rank coal use in slurry feed, entrained-flow gasification. Low to moderate ash fusion-temperature coals are preferred for slagging gasifiers. Coals with high ash fusion temperatures may require flux addition for optimal gasification operation.

3.3.2 PROCESS DESCRIPTION

In this section the overall CoP gasification process is described. The system description follows the BFD in Exhibit 3-48 and stream numbers reference the same Exhibit. The tables in Exhibit 3-49 provide process data for the numbered streams in the BFD.

Coal Grinding and Slurry Preparation

Coal receiving and handling is common to all cases and was covered in Section 3.1.1. The receiving and handling subsystem ends at the coal silo. Coal grinding and slurry preparation is similar to the GEE cases but repeated here for completeness.

Coal from the coal silo is fed onto a conveyor by vibratory feeders located below each silo. The conveyor feeds the coal to an inclined conveyor that delivers the coal to the rod mill feed hopper. The feed hopper provides a surge capacity of about two hours and contains two hopper outlets. Each hopper outlet discharges onto a weigh feeder, which in turn feeds a rod mill. Each rod mill is sized to process 55 percent of the coal feed requirements of the gasifier. The rod mill grinds the coal and wets it with treated slurry water transferred from the slurry water tank by the slurry water pumps. The coal slurry is discharged through a trommel screen into the rod mill discharge tank, and then the slurry is pumped to the slurry storage tanks. The dry solids concentration of the final slurry is 63 percent. The Polk Power Station operates at a slurry concentration of 62-68 percent using bituminous coal and CoP presented a paper showing the slurry concentration of Illinois No. 6 coal as 63 percent. [41, 49]

The coal grinding system is equipped with a dust suppression system consisting of water sprays aided by a wetting agent. The degree of dust suppression required depends on local environmental regulations. All of the tanks are equipped with vertical agitators to keep the coal slurry solids suspended.

The equipment in the coal grinding and slurry preparation system is fabricated of materials appropriate for the abrasive environment present in the system. The tanks and agitators are rubber lined. The pumps are either rubber-lined or hardened metal to minimize erosion. Piping is fabricated of high-density polyethylene (HDPE).

Gasification

This plant utilizes two gasification trains to process a total of 5,050 tonnes/day (5,567 TPD) of Illinois No. 6 coal. Each of the 2 x 50 percent gasifiers operate at maximum capacity. The E-Gas™ two-stage coal gasification technology features an oxygen-blown, entrained-flow, refractory-lined gasifier with continuous slag removal. About 78 percent of the total slurry feed is fed to the first (or bottom) stage of the gasifier. All oxygen for gasification is fed to this stage of the gasifier at a pressure of 4.2 MPa (615 psia). This stage is best described as a horizontal cylinder with two horizontally opposed burners. The highly exothermic gasification/oxidation reactions take place rapidly at temperatures of 1,316 to 1,427°C (2,400 to 2,600°F). The hot raw gas from the first stage enters the second (top) stage, which is a vertical cylinder perpendicular to the first stage. The remaining 22 percent of coal slurry is injected into this hot raw gas. The endothermic gasification/devolatilization reaction in this stage reduces the final gas temperature to about 1,010°C (1,850°F). Total slurry to both stages is shown as stream 6 in Exhibit 3-48.

Exhibit 3-48 Case 3 Process Flow Diagram, E-Gas™ IGCC without CO_2 Capture

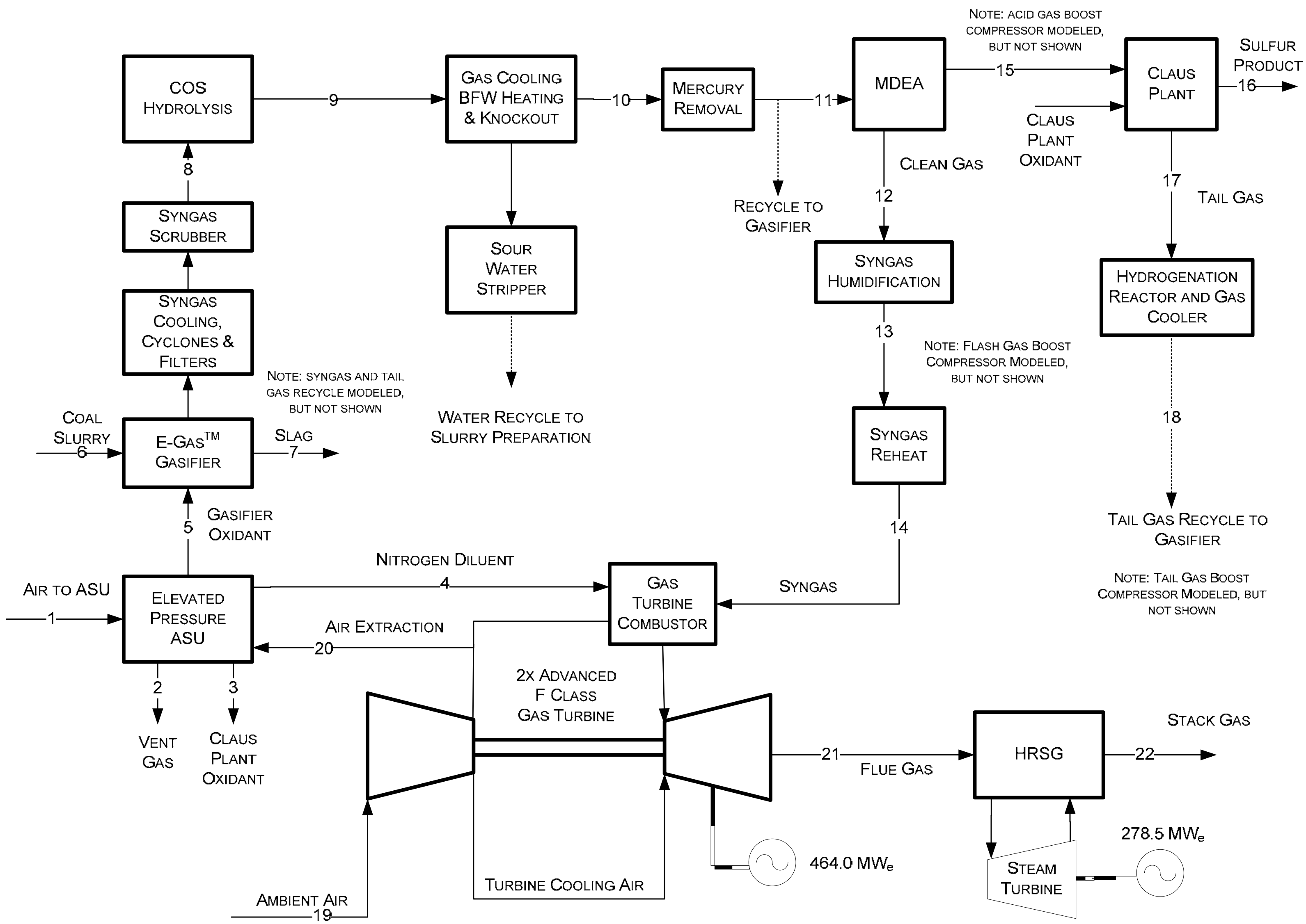

Exhibit 3-49 Case 3 Stream Table, E-Gas™ IGCC without CO_2 Capture

	1	2	3	4	5	6[A]	7	8	9	10	11
V-L Mole Fraction											
Ar	0.0092	0.0262	0.0360	0.0024	0.0320	0.0000	0.0000	0.0080	0.0080	0.0092	0.0092
CH_4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0400	0.0400	0.0457	0.0457
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3851	0.3851	0.4403	0.4403
CO_2	0.0003	0.0090	0.0000	0.0000	0.0000	0.0000	0.0000	0.1468	0.1473	0.1685	0.1685
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0005	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2738	0.2738	0.3134	0.3134
H_2O	0.0099	0.2756	0.0000	0.0004	0.0000	1.0000	0.0000	0.1251	0.1246	0.0018	0.0018
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0079	0.0084	0.0092	0.0092
N_2	0.7732	0.4638	0.0140	0.9919	0.0180	0.0000	0.0000	0.0102	0.0102	0.0117	0.0117
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0026	0.0026	0.0002	0.0002
O_2	0.2074	0.2254	0.9500	0.0054	0.9500	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	41,839	1,917	242	40,619	10,830	13,452	0	55,289	55,289	48,292	38,633
V-L Flowrate (lb/hr)	1,207,360	51,005	7,811	1,139,740	348,539	242,145	0	1,196,610	1,196,610	1,070,040	856,032
Solids Flowrate (lb/hr)	0	0	0	0	0	412,305	47,201	0	0	0	0
Temperature (°F)	235	70	90	385	191	140	1,850	400	401	103	103
Pressure (psia)	190.0	16.4	125.0	460.0	740.0	850.0	850.0	554.7	544.7	504.7	494.7
Enthalpy (BTU/lb)[B]	55.7	26.8	12.5	88.0	34.4	---	1,120	241.5	241.4	25.0	25.0
Density (lb/ft^3)	0.735	0.104	0.683	1.424	3.412	---	---	1.302	1.277	1.852	1.815
Molecular Weight	28.857	26.613	32.229	28.060	32.181	---	---	21.643	21.643	22.158	22.158

A - Solids flowrate includes dry coal; V-L flowrate includes slurry water and water from coal

B - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 3-49 Case 3 Stream Table Continued

	12	13	14	15	16	17	18	19	20	21	22
V-L Mole Fraction											
Ar	0.0095	0.0088	0.0088	0.0000	0.0000	0.0059	0.0092	0.0094	0.0094	0.0088	0.0088
CH_4	0.0471	0.0434	0.0434	0.0001	0.0000	0.0000	0.0383	0.0000	0.0000	0.0000	0.0000
CO	0.4544	0.4189	0.4189	0.0014	0.0000	0.0910	0.0003	0.0000	0.0000	0.0000	0.0000
CO_2	0.1513	0.1395	0.1395	0.7034	0.0000	0.4812	0.8551	0.0003	0.0003	0.0822	0.0822
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0004	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.3235	0.2982	0.2982	0.0010	0.0000	0.0186	0.0097	0.0000	0.0000	0.0000	0.0000
H_2O	0.0019	0.0798	0.0798	0.0000	0.0000	0.3490	0.0023	0.0108	0.0108	0.0718	0.0718
H_2S	0.0000	0.0000	0.0000	0.2941	0.0000	0.0068	0.0140	0.0000	0.0000	0.0000	0.0000
N_2	0.0120	0.0111	0.0111	0.0000	0.0000	0.0454	0.0710	0.7719	0.7719	0.7360	0.7360
NH_3	0.0002	0.0002	0.0002	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2076	0.2076	0.1012	0.1012
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0017	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	37,428	40,600	40,600	1,205	0	1,596	1,021	243,395	12,038	298,016	298,016
V-L Flowrate (lb/hr)	806,593	863,729	863,729	49,439	0	50,953	42,010	7,021,820	347,293	8,678,000	8,678,000
Solids Flowrate (lb/hr)	0	0	0	0	11,591	0	0	0	0	0	0
Temperature (°F)	99	266	385	187	368	320	251	59	811	1,111	270
Pressure (psia)	494.2	484.2	479.2	30.0	24.9	24.9	804.1	14.7	234.9	15.2	15.2
Enthalpy (BTU/lb)[B]	24.2	153.9	197.6	33.3	-97.5	288.6	49.1	13.8	200.3	330.6	106.9
Density (lb/ft^3)	1.776	1.324	1.125	0.177	---	0.095	4.340	0.076	0.497	0.026	0.057
Molecular Weight	21.550	21.274	21.274	41.022	---	31.929	41.154	28.849	28.849	29.119	29.119

B - Reference conditions are 32.02 F & 0.089 PSIA

The syngas produced by the CoP gasifier is higher in methane content than either the GEE or Shell gasifier. The two stage design allows for improved cold gas efficiency and lower oxygen consumption, but the quenched second stage allows some CH_4 to remain. The syngas CH_4 concentration exiting the gasifier in Case 3 is 3.9 vol% (compared to 0.10 vol% in Case 1 [GEE] and 0.04 vol% in Case 5 [Shell]). The relatively high CH_4 concentration impacts CO_2 capture efficiency as discussed further in Section 3.3.8.

Raw Gas Cooling/Particulate Removal

The 1,010°C (1,850°F) raw coal gas from the second stage of the gasifier is cooled to 371°C (700°F) in the waste heat recovery (synthesis gas cooler) unit, which consists of a fire-tube boiler and convective superheating and economizing sections. Fire-tube boilers cost markedly less than comparable duty water-tube boilers. This is because of the large savings in high-grade steel associated with containing the hot high-pressure synthesis gas in relatively small tubes.

The coal ash is converted to molten slag, which flows down through a tap hole. The molten slag is quenched in water and removed through a proprietary continuous-pressure letdown/dewatering system (stream 7). Char is produced in the second gasifier stage and is recycled to the hotter first stage, to be gasified.

The cooled gas from the SGC is cleaned of remaining particulate via a cyclone collector followed by a ceramic candle filter. Recycled syngas is used as the pulse gas to clean the candle filters. The recovered fines are pneumatically returned to the first stage of the gasifier. The combination of recycled char and recycled particulate results in high overall carbon conversion (99.2 percent used in this study).

Following particulate removal, additional heat is removed from the syngas to provide syngas re-heat prior to the COS reactor and to generate steam for the LP steam header. In this manner the syngas is cooled to 166°C (330°F) prior to the syngas scrubber.

Syngas Scrubber/Sour Water Stripper

Syngas exiting the second of the two low temperature heat exchangers passes to a syngas scrubber where a water wash is used to remove chlorides and particulate. The syngas exits the scrubber saturated at 152°C (305°F).

The sour water stripper removes NH_3, SO_2, and other impurities from the scrubber and other waste streams. The stripper consists of a sour drum that accumulates sour water from the gas scrubber and condensate from synthesis gas coolers. Sour water from the drum flows to the sour stripper, which consists of a packed column with a steam-heated reboiler. Sour gas is stripped from the liquid and sent to the sulfur recovery unit. Remaining water is sent to wastewater treatment.

COS Hydryolysis, Mercury Removal and Acid Gas Removal

Syngas exiting the scrubber is reheated to 400°F and enters a COS hydrolysis reactor (stream 8). About 99.5 percent of the COS is converted to CO_2 and H_2O (Section 3.1.5). The gas exiting the COS reactor (stream 9) passes through a series of heat exchangers and knockout drums to lower the syngas temperature to 39°C (103°F) and to separate entrained water. The cooled syngas (stream 10) then passes through a carbon bed to remove 95 percent of the Hg (Section 3.1.4).

Cool, particulate-free synthesis gas (stream 11) enters the absorber unit at approximately 3.4 MPa (495 psia) and 39°C (103°F). In the absorber, H_2S is preferentially removed from the fuel gas stream by contact with MDEA. The absorber column is operated at 27°C (80°F) by refrigerating the lean MDEA solvent. The lower temperature is required to achieve an outlet H_2S concentration of less than 30 ppmv in the sweet syngas. The stripper acid gas stream (stream 15), consisting of 29 percent H_2S and 70 percent CO_2, is sent to the Claus unit. The acid gas is combined with the sour water stripper off gas and introduced into the Claus plant burner section.

Claus Unit

Acid gas from the MDEA unit is preheated to 232°C (450°F). A portion of the acid gas along with all of the sour gas from the stripper and oxygen from the ASU are fed to the Claus furnace. In the furnace, H_2S is catalytically oxidized to SO_2 at a furnace temperature of 1,316°C (2,400°F), which must be maintained in order to thermally decompose all of the NH_3 present in the sour gas stream.

Following the thermal stage and condensation of sulfur, two reheaters and two sulfur converters are used to obtain a per-pass H_2S conversion of approximately 99.5 percent. The Claus Plant tail gas is hydrogenated and recycled back to the gasifier (stream 18). In the furnace waste heat boiler, 14,710 kg/h (32,430 lb/h) of 4.0 MPa (575 psia) steam is generated. This steam is used to satisfy all Claus process preheating and reheating requirements as well as to provide some steam to the medium-pressure steam header. The sulfur condensers produce 0.34 MPa (50 psig) steam for the low-pressure steam header.

A flow rate of 5,258 kg/h (11,591 lb/h) of elemental sulfur (stream 16) is recovered from the fuel gas stream. This value represents an overall sulfur recovery efficiency of 99.5 percent.

Power Block

Clean syngas exiting the MDEA absorber (stream 12) is partially humidified (stream 13) because there is not sufficient nitrogen from the ASU to provide the level of dilution required to reach the target syngas heating value. The moisturized syngas stream is reheated (stream 14), further diluted with nitrogen from the ASU (stream 4) and enters the advanced F Class combustion turbine (CT) burner. The CT compressor provides combustion air to the burner and also 22 percent of the total ASU air requirement (stream 20). The exhaust gas exits the CT at 599°C (1,111°F) (stream 21) and enters the HRSG where additional heat is recovered until the flue gas exits the HRSG at 132°C (270°F) (stream 22) and is discharged through the plant stack. The steam raised in the HRSG is used to power an advanced, commercially available steam turbine using a 12.4 MPa/566°C/566°C (1800 psig/1050°F/1050°F) steam cycle.

Air Separation Unit (ASU)

The elevated pressure ASU was described in Section 3.1.2. In Case 3 the ASU is designed to produce a nominal output of 3,880 tonnes/day (4,275 TPD) of 95 mole percent O_2 for use in the gasifier (stream 5) and Claus plant (stream 3). The plant is designed with two production trains. The air compressor is powered by an electric motor. Approximately 12,410 tonnes/day (13,680 TPD) of nitrogen are also recovered, compressed, and used as dilution in the gas turbine combustor (stream 4). About 4.9 percent of the gas turbine air is used to supply approximately 22 percent of the ASU air requirements (stream 20).

Balance of Plant

Balance of plant items were covered in Sections 3.1.9, 3.1.10 and 3.1.11.

3.3.3 KEY SYSTEM ASSUMPTIONS

System assumptions for Cases 3 and 4, CoP IGCC with and without CO_2 capture, are compiled in Exhibit 3-50.

Balance of Plant – Cases 3 and 4

The balance of plant assumptions are common to all cases and were presented previously in Exhibit 3-17.

3.3.4 SPARING PHILOSOPHY

The sparing philosophy for Cases 3 and 4 is provided below. Single trains are utilized throughout with exceptions where equipment capacity requires an additional train. There is no redundancy other than normal sparing of rotating equipment.

The plant design consists of the following major subsystems:

- Two air separation units (2 x 50%)
- Two trains of slurry preparation and slurry pumps (2 x 50%)
- Two trains of gasification, including gasifier, synthesis gas cooler, cyclone, and barrier filter (2 x 50%).
- Two trains of syngas clean-up process (2 x 50%).
- Two trains of refrigerated MDEA acid gas gas removal in Case 3 and two-stage Selexol in Case 4 (2 x 50%),
- One train of Claus-based sulfur recovery (1 x 100%).
- Two combustion turbine/HRSG tandems (2 x 50%).
- One steam turbine (1 x 100%).

Exhibit 3-50 CoP IGCC Plant Study Configuration Matrix

Case	3	4
Gasifier Pressure, MPa (psia)	4.2 (615)	4.2 (615)
O_2:Coal Ratio, kg O_2/kg dry coal	0.85	0.85
Carbon Conversion, %	99.2	99.2
Syngas HHV at MDEA Outlet, kJ/Nm^3 (Btu/scf)	11,131 (299)	12,918 (347)
Steam Cycle, MPa/°C/°C (psig/°F/°F)	12.4/566/566 (1800/1050/1050)	12.4/538/538 (1800/1000/1000)
Condenser Pressure, mm Hg (in Hg)	51 (2.0)	51 (2.0)
Combustion Turbine	2x Advanced F Class (232 MW output each)	2x Advanced F Class (232 MW output each)
Gasifier Technology	CoP E-Gas™	CoP E-Gas™
Oxidant	95 vol% Oxygen	95 vol% Oxygen
Coal	Illinois No. 6	Illinois No. 6
Coal Slurry Solids Conent, %	63	63
COS Hydrolysis	Yes	Occurs in SGS
Sour Gas Shift	No	Yes
H_2S Separation	Refrigerated MDEA	Selexol 1st Stage
Sulfur Removal, %	99.5	99.7
Sulfur Recovery	Claus Plant with Tail Gas Recycle to Gasifier/ Elemental Sulfur	Claus Plant with Tail Gas Recycle to Gasifier/ Elemental Sulfur
Particulate Control	Cyclone, Candle Filter, Scrubber, and AGR Absorber	Cyclone, Candle Filter, Scrubber, and AGR Absorber
Mercury Control	Carbon Bed	Carbon Bed
NOx Control	MNQC (LNB), N_2 Dilution and Humidification	MNQC (LNB), N_2 Dilution and Humidification
CO_2 Separation	N/A	Selexol 2nd Stage
CO_2 Capture	N/A	88.4% from Syngas
CO_2 Sequestration	N/A	Off-site Saline Formation

3.3.5 CASE 3 PERFORMANCE RESULTS

The plant produces a net output of 623 MWe at a net plant efficiency of 39.3 percent (HHV basis). CoP recently reported the same efficiency for their gasifier using Illinois No. 6 coal and an amine based AGR. [49]

Overall performance for the entire plant is summarized in Exhibit 3-51 which includes auxiliary power requirements. The ASU accounts for over 76 percent of the total auxiliary load distributed between the main air compressor, the oxygen compressor, the nitrogen compressor, and ASU auxiliaries. The cooling water system, including the circulating water pumps and cooling tower fan, accounts for over 4 percent of the auxiliary load, and the BFW pumps account for an additional 3.6 percent. All other individual auxiliary loads are less than 3 percent of the total.

Exhibit 3-51 Case 3 Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine Power	464,030
Steam Turbine Power	278,480
TOTAL POWER, kWe	**742,510**
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	440
Coal Milling	2,160
Coal Slurry Pumps	570
Slag Handling and Dewatering	1,110
Air Separation Unit Auxiliaries	1,000
Air Separation Unit Main Air Compressor	47,130
Oxygen Compressor	8,240
Nitrogen Compressor	34,680
Syngas Recycle Blower	2,130
Tail Gas Recycle Blower	1,760
Boiler Feedwater Pumps	4,280
Condensate Pump	220
Flash Bottoms Pump	200
Circulating Water Pumps	3,350
Cooling Tower Fans	1,730
Scrubber Pumps	70
SS Amine Unit Auxiliaries	3,230
Gas Turbine Auxiliaries	1,000
Steam Turbine Auxiliaries	100
Claus Plant/TGTU Auxiliaries	200
Miscellaneous Balance of Plant (Note 1)	3,000
Transformer Loss	2,540
TOTAL AUXILIARIES, kWe	**119,140**
NET POWER, kWe	**623,370**
Net Plant Efficiency, % (HHV)	39.3
Net Plant Heat Rate (Btu/kWh)	8,681
CONDENSER COOLING DUTY 10^6 kJ/h (10^6 Btu/h)	**1,468 (1,393)**
CONSUMABLES	
As-Received Coal Feed, kg/h (lb/h)	210,417 (463,889)
Thermal Input, kWt	1,586,023
Raw Water Usage, m^3/min (gpm)	14.2 (3,757)

Note 1: Includes plant control systems, lighting, HVAC and miscellaneous low voltage loads

Environmental Performance

The environmental targets for emissions of Hg, NOx, SO_2 and particulate matter were presented in Section 2.4. A summary of the plant air emissions for Case 3 is presented in Exhibit 3-52.

Exhibit 3-52 Case 3 Air Emissions

	kg/GJ ($lb/10^6$ Btu)	Tonne/year (ton/year) 80% capacity factor	kg/MWh (lb/MWh)
SO_2	0.0054 (0.0125)	215 (237)	0.041 (0.091)
NO_X	0.026 (0.059)	1,021 (1,126)	0.196 (0.433)
Particulates	0.003 (0.0071)	122 (135)	0.023 (0.052)
Hg	$0.25x10^{-6}$ ($0.57x10^{-6}$)	0.010 (0.011)	$1.9x10^{-6}$ ($4.2x10^{-6}$)
CO_2	85.7 (199)	3,427,000 (3,778,000)	659 (1,452)
CO_2[1]			785 (1,730)

[1] CO_2 emissions based on net power instead of gross power

The low level of SO_2 in the plant emissions is achieved by capture of the sulfur in the gas by the refrigerated Coastal SS Amine AGR process. The AGR process removes over 99 percent of the sulfur compounds in the fuel gas down to a level of less than 30 ppmv. This results in a concentration in the flue gas of less than 4 ppmv. The H_2S-rich regeneration gas from the AGR system is fed to a Claus plant, producing elemental sulfur. The Claus plant tail gas is hydrogenated to convert all sulfur species to H_2S and then recycled back to the gasifier, thereby eliminating the need for a tail gas treatment unit.

NO_X emissions are limited by the use of nitrogen dilution (primarily) and humidification (to a lesser extent) to 15 ppmvd (as NO_2 @ 15 percent O_2). Ammonia in the syngas is removed with process condensate prior to the low-temperature AGR process and destroyed in the Claus plant burner. This helps lower NO_X levels as well.

Particulate discharge to the atmosphere is limited to extremely low values by the use of a cyclone and a barrier filter in addition to the syngas scrubber and the gas washing effect of the AGR absorber. The particulate emissions represent filterable particulate only.

Ninety five percent of the mercury is captured from the syngas by an activated carbon bed. CO_2 emissions represent the uncontrolled discharge from the process.

The carbon balance for the plant is shown in Exhibit 3-53. The carbon input to the plant consists of carbon in the air in addition to carbon in the coal. Carbon in the air is not neglected here since the Aspen model accounts for air components throughout. Carbon leaves the plant as unburned carbon in the slag, as dissolved CO_2 in the wastewater blowdown stream, and CO_2 in the stack gas and ASU vent gas. Carbon in the wastewater blowdown stream is calculated by difference to close the material balance.

Exhibit 3-53 Case 3 Carbon Balance

Carbon In, kg/hr (lb/hr)		Carbon Out, kg/hr (lb/hr)	
Coal	134,141 (295,729)	**Slag**	1,006 (2,218)
Air (CO_2)	465 (1,026)	**Stack Gas**	133,374 (294,039)
		ASU Vent	94 (207)
		Wastewater	132 (291)
Total	134,606 (296,755)	**Total**	134,606 (296,755)

Exhibit 3-54 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered in the Claus plant, dissolved SO_2 in the wastewater blowdown stream, and sulfur emitted in the stack gas. Sulfur in the slag is considered to be negligible, and the sulfur content of the blowdown stream is calculated by difference to close the material balance. The total sulfur capture is represented by the following fraction:

(Sulfur byproduct/Sulfur in the coal) or
(11,591/11,644) or
99.5 percent

Exhibit 3-54 Case 3 Sulfur Balance

Sulfur In, kg/hr (lb/hr)		Sulfur Out, kg/hr (lb/hr)	
Coal	5,281 (11,644)	**Elemental Sulfur**	5,257 (11,591)
		Stack Gas	15 (34)
		Wastewater	9 (19)
Total	5,281 (11,644)	**Total**	5,281 (11,644)

Exhibit 3-55 shows the overall water balance for the plant. Raw water is obtained from groundwater (50 percent) and from municipal sources (50 percent). Water demand represents the total amount of water required for a particular process. Some water is recovered within the process, primarily as syngas condensate, and that water is re-used as internal recycle. Raw water makeup is the difference between water demand and internal recycle.

Exhibit 3-55 Case 3 Water Balance

Water Use	Water Demand, m^3/min (gpm)	Internal Recycle, m^3/min (gpm)	Raw Water Makeup, m^3/min (gpm)
Slurry	1.4 (381)	1.1 (292)	0.3 (89)
Slag Handling	0.5 (123)	0	0.5 (123)
Syngas Humidifier	0.5 (133)	0	0.5 (133)
BFW Makeup	0.2 (40)	0	0.2 (40)
Cooling Tower Makeup	13.0 (3,442)	0.3 (70)	12.7 (3,372)
Total	**15.6 (4,119)**	**1.4 (362)**	**14.2 (3,757)**

Heat and Mass Balance Diagrams

Heat and mass balance diagrams are shown for the following subsystems in Exhibit 3-56 through Exhibit 3-60:

- Coal gasification and air separation unit
- Syngas cleanup
- Sulfur recovery and tail gas recycle
- Combined cycle power generation
- Steam and feedwater

An overall plant energy balance is provided in tabular form in Exhibit 3-61. The power out is the combined combustion turbine and steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 3-51) is calculated by multiplying the power out by a combined generator efficiency of 98.3 percent.

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Exhibit 3-56 Case 3 Coal Gasification and Air Separation Unit Heat and Mass Balance Schematic

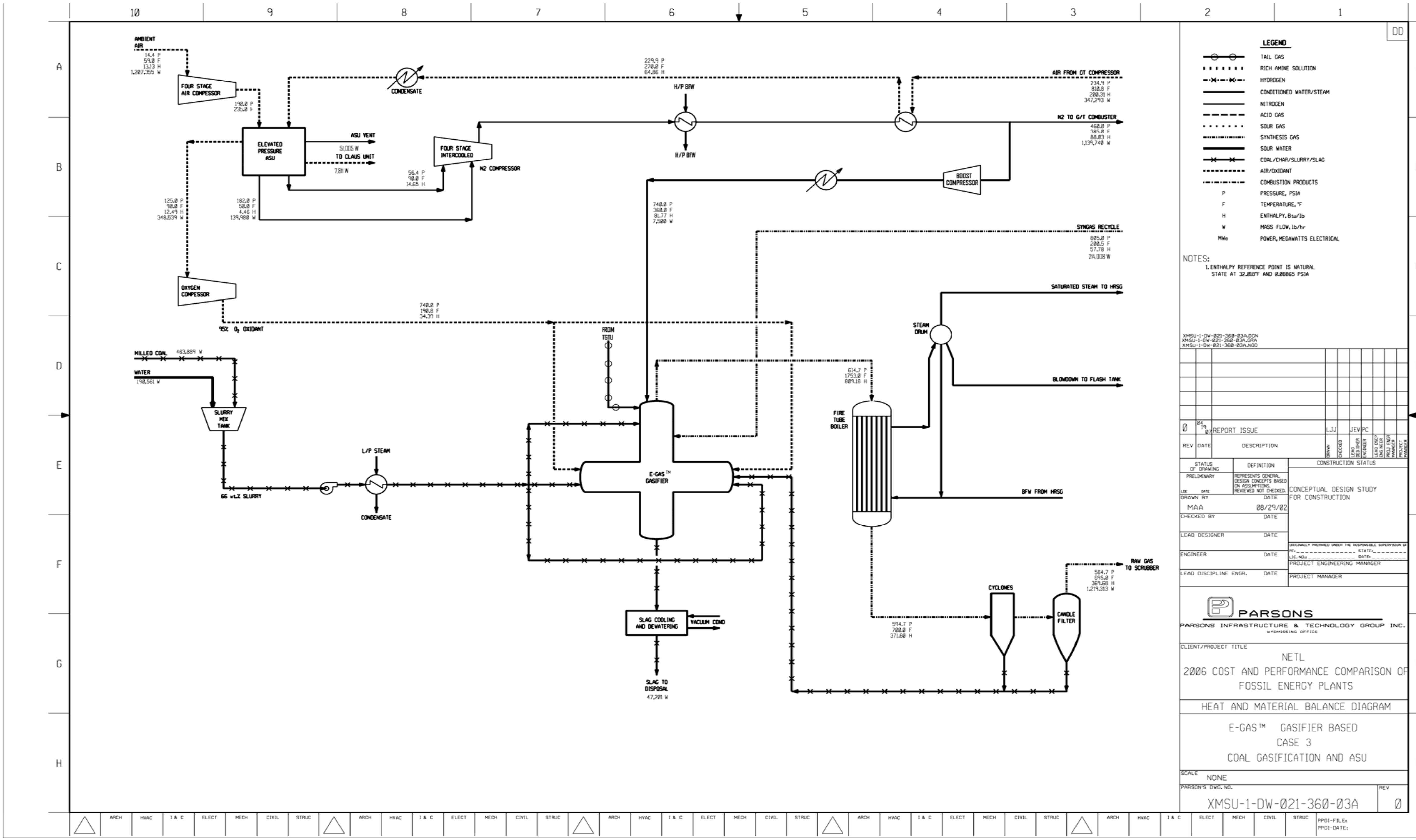

Exhibit 3-57 Case 3 Syngas Cleanup Heat and Mass Balance Schematic

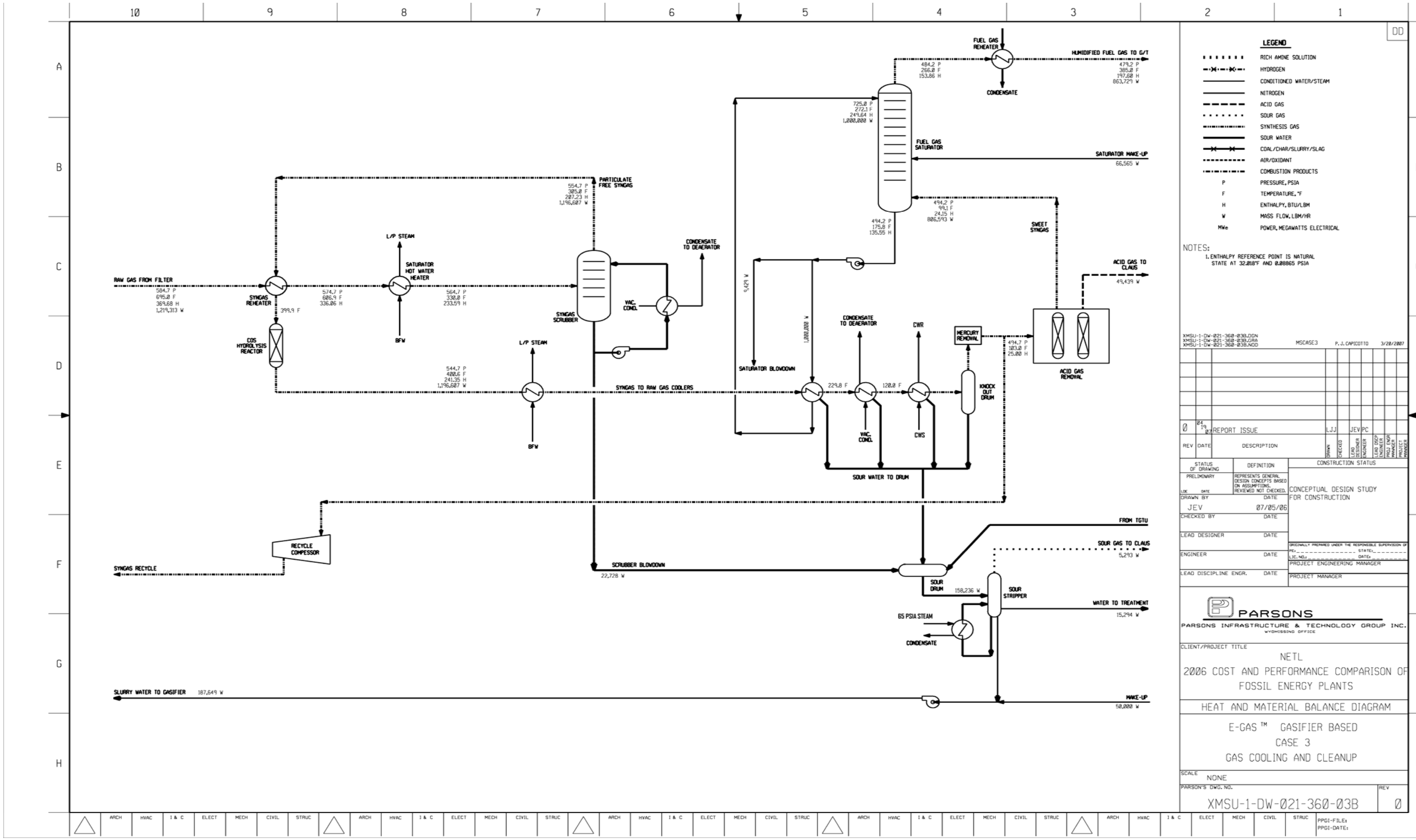

Exhibit 3-58 Case 3 Sulfur Recovery and Tail Gas Recycle Heat and Mass Balance Schematic

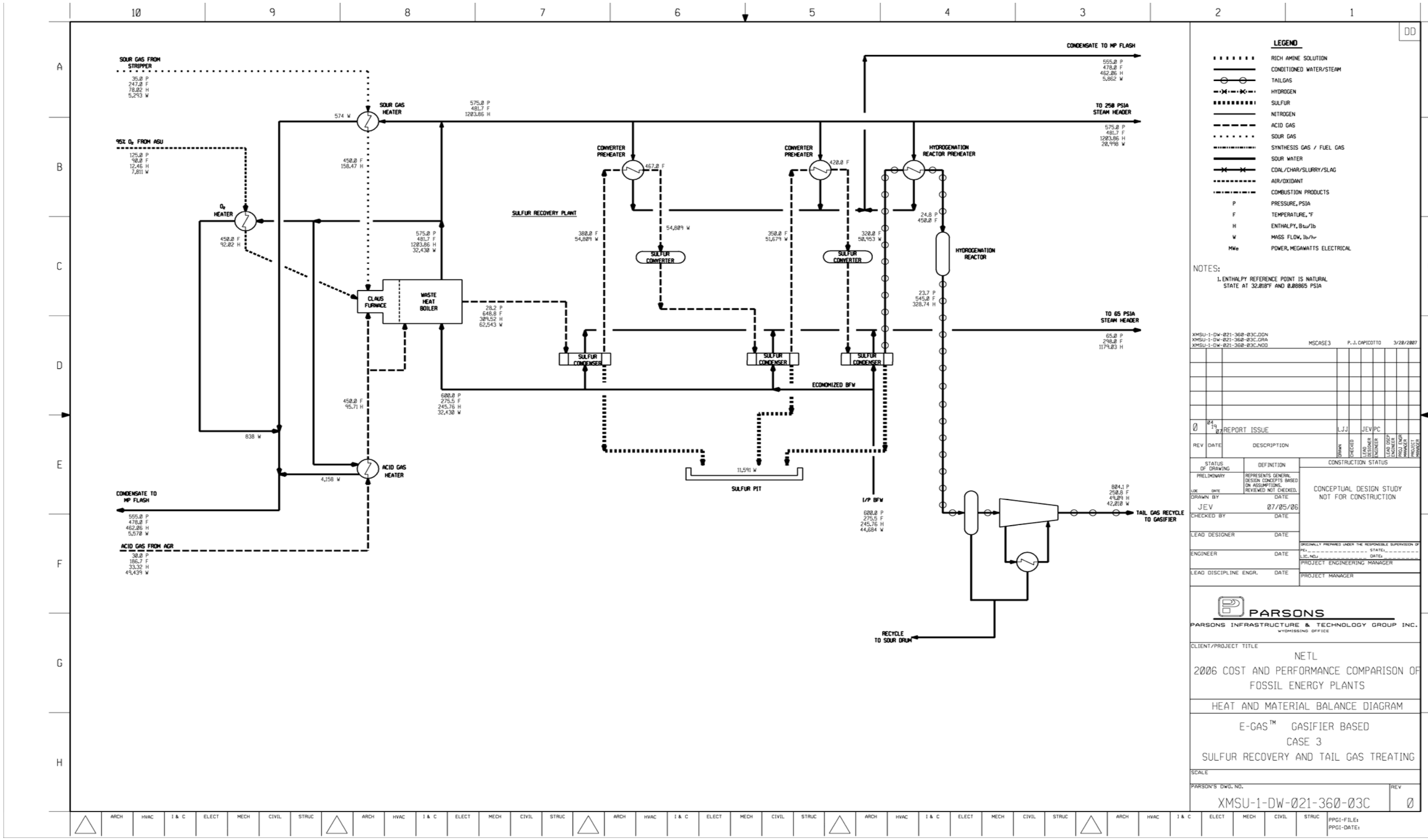

Exhibit 3-59 Case 3 Combined Cycle Power Generation Heat and Mass Balance Schematic

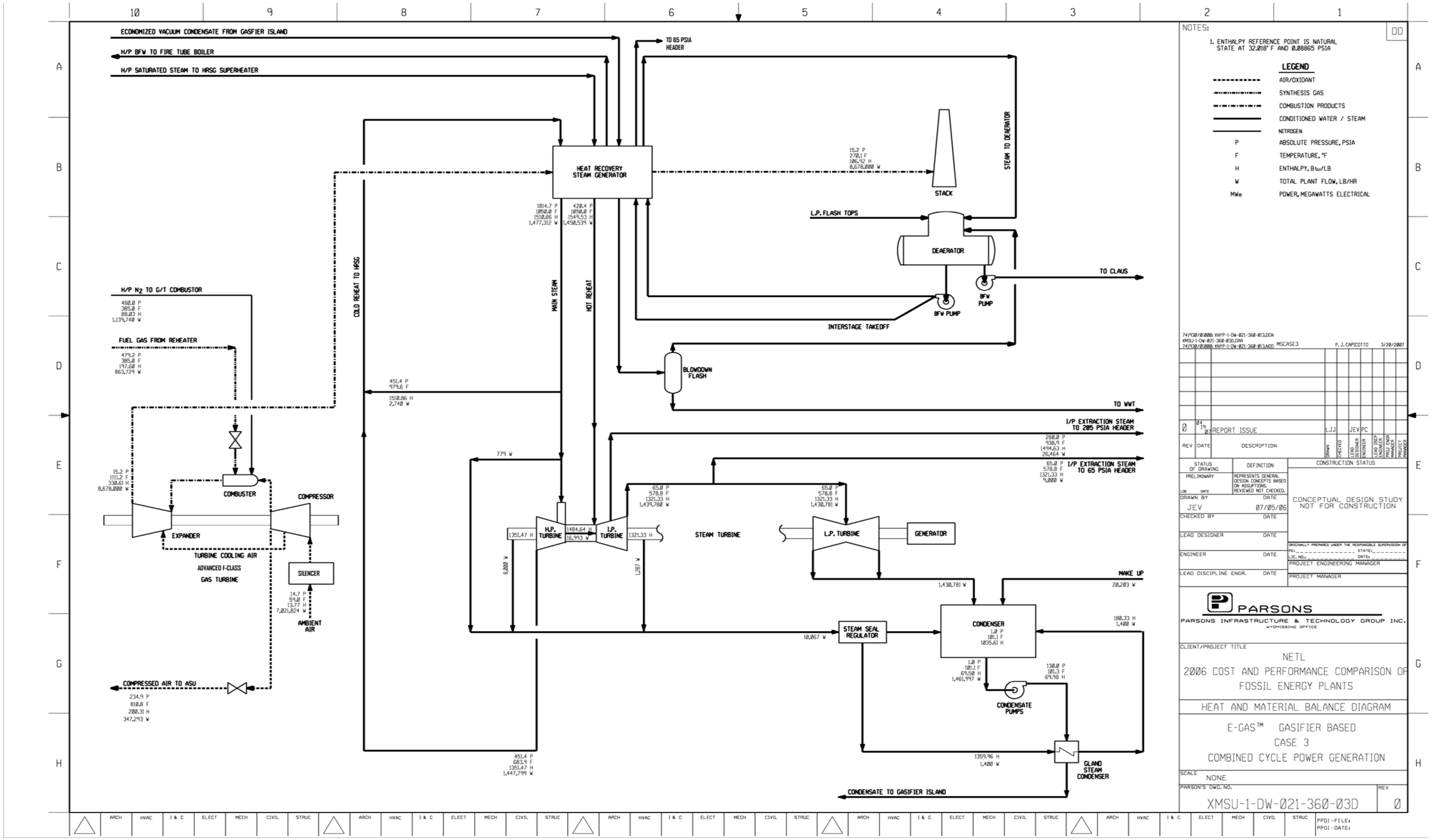

Exhibit 3-60 Case 3 Steam and Feedwater Heat and Mass Balance Schematic

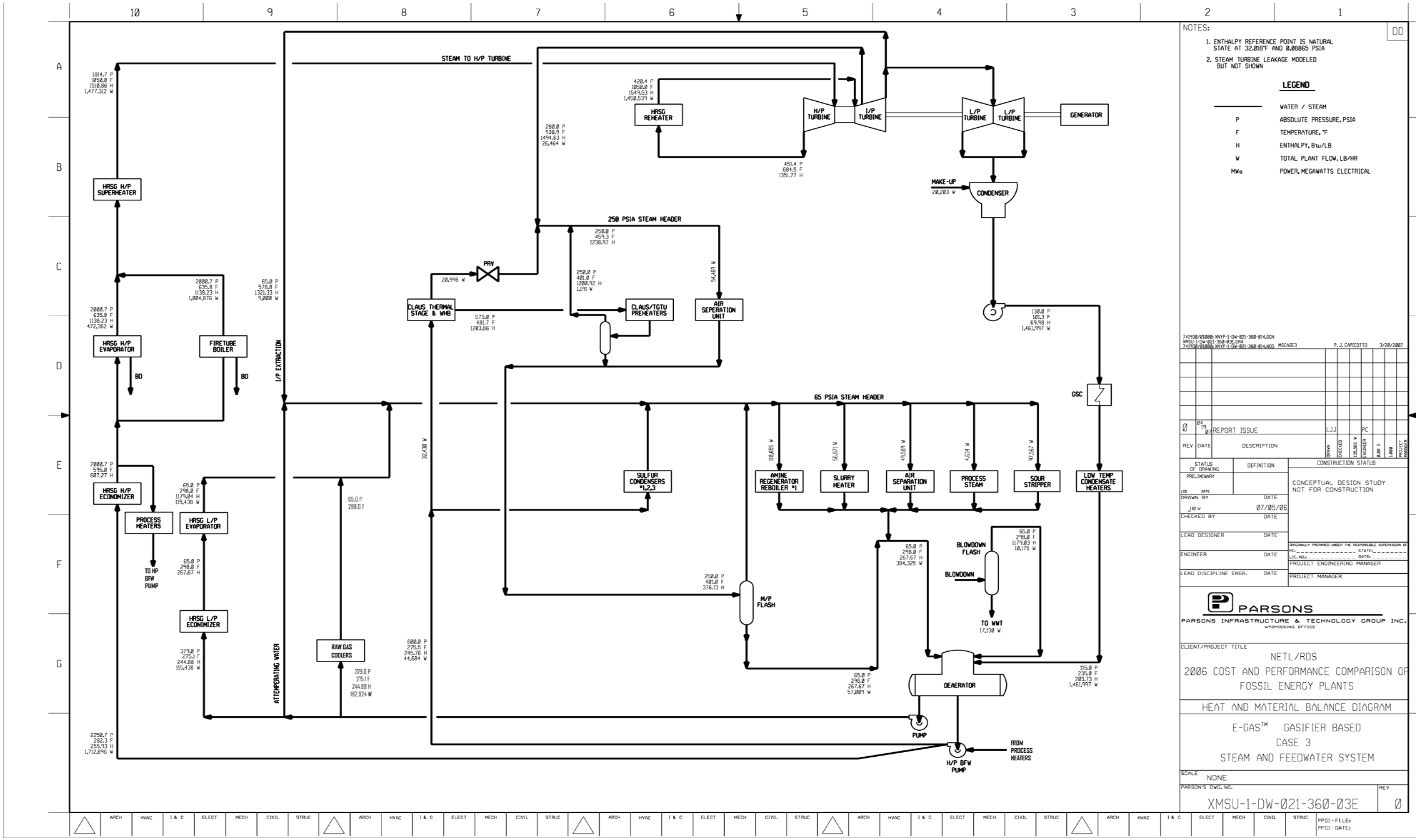

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Exhibit 3-61 Case 3 Overall Energy Balance (0°C [32°F] Reference)

	HHV	Sensible + Latent	Power	Total
Heat In (MMBtu/hr)				
Coal	5,411.7	4.5		5,416.2
ASU Air		15.9		15.9
CT Air		96.7		96.7
Water		4.3		4.3
Auxiliary Power			406.5	406.5
Totals	**5,411.7**	**121.3**	**406.5**	**5,939.6**
Heat Out (MMBtu/hr)				
ASU Intercoolers		203.0		203.0
ASU Vent		1.4		1.4
Slag	31.3	21.6		52.9
Sulfur	46.2	(1.1)		45.0
Tail Gas Compressor Intercoolers		6.3		6.3
HRSG Flue Gas		928.0		928.0
Condenser		1,393.0		1,393.0
Process Losses		732.1		732.1
Power			2,577.9	2,577.9
Totals	**77.5**	**3,284.2**	**2,577.9**	**5,939.6**

(1) Process Losses are calculated by difference and reflect various gasification, turbine, HRSG and other heat and work losses. Aspen flowsheet balance is within 0.5 percent.

3.3.6 CASE 3 - MAJOR EQUIPMENT LIST

Major equipment items for the CoP gasifier with no CO_2 capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 3.3.7. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

ACCOUNT 1 COAL HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	181 tonne (200 ton)	2	0
2	Feeder	Belt	572 tonne/h (630 tph)	2	0
3	Conveyor No. 1	Belt	1,134 tonne/h (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,134 tonne/h (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,134 tonne/h (1,250 tph)	1	0
8	Reclaim Hopper	N/A	45 tonne (50 ton)	2	1
9	Feeder	Vibratory	172 tonne/h (190 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	345 tonne/h (380 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	172 tonne (190 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3" x 0 - 1-1/4" x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	345 tonne/h (380 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	345 tonne/h (380 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	816 tonne (900 ton)	3	0

ACCOUNT 2 COAL PREPARATION AND FEED

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Feeder	Vibratory	82 tonne/h (90 tph)	3	0
2	Conveyor No. 6	Belt w/tripper	236 tonne/h (260 tph)	1	0
3	Rod Mill Feed Hopper	Dual Outlet	463 tonne (510 ton)	1	0
4	Weigh Feeder	Belt	118 tonne/h (130 tph)	2	0
5	Rod Mill	Rotary	118 tonne/h (130 tph)	2	0
6	Slurry Water Storage Tank with Agitator	Field erected	283,908 liters (75,000 gal)	2	0
7	Slurry Water Pumps	Centrifugal	795 lpm (210 gpm)	2	2
10	Trommel Screen	Coarse	163 tonne/h (180 tph)	2	0
11	Rod Mill Discharge Tank with Agitator	Field erected	303,592 liters (80,200 gal)	2	0
12	Rod Mill Product Pumps	Centrifugal	2,536 lpm (670 gpm)	2	2
13	Slurry Storage Tank with Agitator	Field erected	908,506 liters (240,000 gal)	2	0
14	Slurry Recycle Pumps	Centrifugal	5,072 lpm (1,340 gpm)	2	2
15	Slurry Product Pumps	Positive displacement	2,536 lpm (670 gpm)	2	2

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	1,101,563 liters (291,000 gal)	2	0
2	Condensate Pumps	Vertical canned	6,132 lpm @ 91 m H2O (1,620 gpm @ 300 ft H2O)	2	1
3	Deaerator (integral w/ HRSG)	Horizontal spray type	463,118 kg/h (1,021,000 lb/h)	2	0
4	Intermediate Pressure Feedwater Pump	Horizontal centrifugal, single stage	1,325 lpm @ 283 m H2O (350 gpm @ 930 ft H2O)	2	1
5	High Pressure Feedwater Pump No. 1	Barrel type, multi-stage, centrifugal	HP water: 6,511 lpm @ 1,890 m H2O (1,720 gpm @ 6,200 ft H2O)	2	1
6	High Pressure Feedwater Pump No. 2	Barrel type, multi-stage, centrifugal	IP water: 909 lpm @ 390 m H2O (240 gpm @ 1,280 ft H2O)	2	1
7	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/h, 2.8 MPa, 343°C (40,000 lb/h, 400 psig, 650°F)	1	0
8	Service Air Compressors	Flooded Screw	28 m3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
9	Instrument Air Dryers	Duplex, regenerative	28 m3/min (1,000 scfm)	2	1
10	Closed Cylce Cooling Heat Exchangers	Plate and frame	58 MMkJ/h (55 MMBtu/h) each	2	0
11	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,820 lpm @ 21 m H2O (5,500 gpm @ 70 ft H2O)	2	1
12	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 107 m H2O (1,000 gpm @ 350 ft H2O)	1	1
13	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 76 m H2O (700 gpm @ 250 ft H2O)	1	1
14	Raw Water Pumps	Stainless steel, single suction	7,912 lpm @ 18 m H2O (2,090 gpm @ 60 ft H2O)	2	1
15	Filtered Water Pumps	Stainless steel, single suction	1,476 lpm @ 49 m H2O (390 gpm @ 160 ft H2O)	2	1
16	Filtered Water Tank	Vertical, cylindrical	715,448 liter (189,000 gal)	2	0
17	Makeup Water Demineralizer	Anion, cation, and mixed bed	151 lpm (40 gpm)	2	0
18	Liquid Waste Treatment System		10 years, 24-hour storm	1	0

ACCOUNT 4 GASIFIER, ASU AND ACCESSORIES INCLUDING LOW TEMPERATURE HEAT RECOVERY AND FUEL GAS SATURATION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gasifier	Pressurized two-stage, slurry-feed entrained bed	2,812 tonne/day, 4.2 MPa (3,100 tpd, 615 psia)	2	0
2	Synthesis Gas Cooler	Fire-tube boiler	304,361 kg/h (671,000 lb/h)	2	0
3	Synthesis Gas Cyclone	High efficiency	291,660 kg/h (643,000 lb/h) Design efficiency 90%	2	0
4	Candle Filter	Pressurized filter with pulse-jet cleaning	metallic filters	2	0
5	Syngas Scrubber Including Sour Water Stripper	Vertical upflow	298,464 kg/h (658,000 lb/h)	2	0
6	Raw Gas Coolers	Shell and tube with condensate drain	275,784 kg/h (608,000 lb/h)	6	0
7	Raw Gas Knockout Drum	Vertical with mist eliminator	266,259 kg/h, 39°C, 3.6 MPa (587,000 lb/h, 103°F, 515 psia)	2	0
8	Saturation Water Economizers	Shell and tube	275,784 kg/h (608,000 lb/h)	2	0
9	Fuel Gas Saturator	Vertical tray tower	201,395 kg/h, 130°C, 3.3 MPa (444,000 lb/h, 266°F, 484 psia)	2	0
10	Saturator Water Pump	Centrifugal	4,543 lpm @ 201 m H2O (1,200 gpm @ 660 ft H2O)	2	2
11	Synthesis Gas Reheater	Shell and tube	215,457 kg/h (475,000 lb/h)	2	0
12	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	298,464 kg/h (658,000 lb/h) syngas	2	0
13	ASU Main Air Compressor	Centrifugal, multi-stage	4,134 m3/min @ 1.3 MPa (146,000 scfm @ 190 psia)	2	0
14	Cold Box	Vendor design	2,177 tonne/day (2,400 tpd) of 95% purity oxygen	2	0
15	Oxygen Compressor	Centrifugal, multi-stage	1,076 m3/min @ 5.1 MPa (38,000 scfm @ 740 psia)	2	0
16	Nitrogen Compressor	Centrifugal, multi-stage	3,540 m3/min @ 3.4 MPa (125,000 scfm @ 490 psia)	2	0
17	Nitrogen Boost Compressor	Centrifugal, multi-stage	481 m3/min @ 2.3 MPa (17,000 scfm @ 340 psia)	2	0
18	Extraction Air Heat Exchanger	Gas-to-gas, vendor design	86,636 kg/h, 433°C, 1.6 MPa (191,000 lb/h, 811°F, 235 psia)	2	0

ACCOUNT 5 SYNGAS CLEANUP

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Mercury Adsorber	Sulfated carbon bed	234,054 kg/h (516,000 lb/h) 39°C (103°F) 3.4 MPa (495 psia)	2	0
2	Sulfur Plant	Claus type	139 tonne/day (153 tpd)	1	0
3	COS Hydrolysis Reactor	Fixed bed, catalytic	298,464 kg/h (658,000 lb/h) 204°C (400°F) 3.8 MPa (555 psia)	2	0
4	Acid Gas Removal Plant	MDEA	213,642 kg/h (471,000 lb/h) 39°C (103°F) 3.3 MPa (485 psia)	2	0
5	Hydrogenation Reactor	Fixed bed, catalytic	25,401 kg/h (56,000 lb/h) 232°C (450°F) 0.2 MPa (25 psia)	1	0
6	Tail Gas Recycle Compressor	Centrifugal	21,772 kg/h @ 6.6 MPa (48,000 lb/h @ 950 psia)	1	0

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gas Turbine	Advanced F class	232 MW	2	0
2	Gas Turbine Generator	TEWAC	260 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	2	0

ACCOUNT 7 HRSG, STACK AND DUCTING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	CS plate, type 409SS liner	76 m (250 ft) high x 8.3 m (27 ft) diameter	1	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	Main steam - 368,554 kg/h, 12.4 MPa/566°C (812,522 lb/h, 1,800 psig/1,050°F) Reheat steam - 361,875 kg/h, 2.9 MPa/566°C (797,796 lb/h, 420 psig/1,050°F)	2	0

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	293 MW 12.4 MPa/566°C/566°C (1800 psig/ 1050°F/1050°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitiation	330 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Steam Bypass	One per HRSG	50% steam flow @ design steam conditions	2	0
4	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,613 MMkJ/h (1,530 MMBtu/h), Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1	0

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	336,904 lpm @ 30 m (89,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT, 1,876 MMkJ/h (1,780 MMBtu/h) heat duty	1	0

ACCOUNT 10 SLAG RECOVERY AND HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Slag Quench Tank	Water bath	223,341 liters (59,000 gal)	2	0
2	Slag Crusher	Roll	12 tonne/h (13 tph)	2	0
3	Slag Depressurizer	Proprietary	12 tonne/h (13 tph)	2	0
4	Slag Receiving Tank	Horizontal, weir	147,632 liters (39,000 gal)	2	0
5	Black Water Overflow Tank	Shop fabricated	68,138 liters (18,000 gal)	2	
6	Slag Conveyor	Drag chain	12 tonne/h (13 tph)	2	0
7	Slag Separation Screen	Vibrating	12 tonne/h (13 tph)	2	0
8	Coarse Slag Conveyor	Belt/bucket	12 tonne/h (13 tph)	2	0
9	Fine Ash Settling Tank	Vertical, gravity	219,556 liters (58,000 gal)	2	0
10	Fine Ash Recycle Pumps	Horizontal centrifugal	38 lpm @ 14 m H2O (10 gpm @ 46 ft H2O)	2	2
11	Grey Water Storage Tank	Field erected	71,923 liters (19,000 gal)	2	0
12	Grey Water Pumps	Centrifugal	265 lpm @ 433 m H2O (70 gpm @ 1,420 ft H2O)	2	2
13	Grey Water Recycle Heat Exchanger	Shell and tube	15,876 kg/h (35,000 lb/h)	2	0
14	Slag Storage Bin	Vertical, field erected	816 tonne (900 tons)	2	0
15	Unloading Equipment	Telescoping chute	100 tonne/h (110 tph)	1	0

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	24 kV/345 kV, 260 MVA, 3-ph, 60 Hz	2	0
2	STG Transformer	Oil-filled	24 kV/345 kV, 190 MVA, 3-ph, 60 Hz	1	0
3	Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 130 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 19 MVA, 3-ph, 60 Hz	1	1
5	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	2	0
6	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
7	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
8	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
9	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

ACCOUNT 12 INSTRUMENTATION AND CONTROLS

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

3.3.7 CASE 3 - COSTS ESTIMATING RESULTS

The cost estimating methodology was described previously in Section 2.6. Exhibit 3-62 shows the total plant capital cost summary organized by cost account and Exhibit 3-63 shows a more detailed breakdown of the capital costs. Exhibit 3-64 shows the initial and annual O&M costs.

The estimated TPC of the CoP gasifier with no CO_2 capture is $1,733/kW. Process contingency represents 2.5 percent of the TPC and project contingency is 13.3 percent. The 20-year LCOE is 75.3 mills/kWh.

Exhibit 3-62 Case 3 Total Plant Cost Summary

Client: USDOE/NETL **Report Date:** 05-Apr-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 03 - ConocoPhillips IGCC w/o CO2
Plant Size: 623.4 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	$13,060	$2,435	$10,233	$0	$0	**$25,728**	$2,088	$0	$5,563	**$33,379**	$54
2	COAL & SORBENT PREP & FEED	$22,211	$4,065	$13,559	$0	$0	**$39,835**	$3,200	$0	$8,607	**$51,642**	$83
3	FEEDWATER & MISC. BOP SYSTEMS	$9,148	$7,886	$8,644	$0	$0	**$25,678**	$2,149	$0	$6,278	**$34,105**	$55
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries	$90,425	$0	$55,527	$0	$0	**$145,952**	$11,971	$21,893	$26,972	**$206,789**	$332
4.2	Syngas Cooling (w/4.1)	w/4.1	$0	w/4.1	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.3	ASU/Oxidant Compression	$137,711	$0	w/equip.	$0	$0	**$137,711**	$11,743	$0	$14,945	**$164,399**	$264
4.4-4.9	Other Gasification Equipment	$18,487	$8,580	$11,695	$0	$0	**$38,763**	$3,285	$0	$9,043	**$51,091**	$82
	SUBTOTAL 4	**$246,624**	**$8,580**	**$67,222**	**$0**	**$0**	**$322,427**	**$26,999**	**$21,893**	**$50,961**	**$422,279**	**$677**
5A	Gas Cleanup & Piping	$50,895	$4,805	$38,080	$0	$0	**$93,780**	$8,032	$104	$20,588	**$122,504**	$197
5B	CO_2 REMOVAL & COMPRESSION	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$82,000	$0	$5,071	$0	$0	**$87,071**	$7,338	$4,354	$9,876	**$108,639**	$174
6.2-6.9	Combustion Turbine Other	$0	$684	$762	$0	$0	**$1,446**	$121	$0	$470	**$2,037**	$3
	SUBTOTAL 6	**$82,000**	**$684**	**$5,833**	**$0**	**$0**	**$88,517**	**$7,459**	**$4,354**	**$10,346**	**$110,676**	**$178**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$33,926	$0	$4,828	$0	$0	**$38,754**	$3,277	$0	$4,203	**$46,234**	$74
7.2-7.9	Ductwork and Stack	$3,123	$2,198	$2,918	$0	$0	**$8,239**	$682	$0	$1,450	**$10,371**	$17
	SUBTOTAL 7	**$37,049**	**$2,198**	**$7,745**	**$0**	**$0**	**$46,992**	**$3,959**	**$0**	**$5,653**	**$56,604**	**$91**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$28,109	$0	$4,930	$0	$0	**$33,039**	$2,837	$0	$3,588	**$39,463**	$63
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$10,092	$953	$7,185	$0	$0	**$18,229**	$1,473	$0	$3,969	**$23,671**	$38
	SUBTOTAL 8	**$38,201**	**$953**	**$12,115**	**$0**	**$0**	**$51,268**	**$4,310**	**$0**	**$7,556**	**$63,135**	**$101**
9	COOLING WATER SYSTEM	$6,760	$7,303	$6,124	$0	$0	**$20,187**	$1,661	$0	$4,492	**$26,340**	$42
10	ASH/SPENT SORBENT HANDLING SYS	$18,173	$1,373	$9,021	$0	$0	**$28,568**	$2,437	$0	$3,382	**$34,386**	$55
11	ACCESSORY ELECTRIC PLANT	$22,608	$9,796	$19,825	$0	$0	**$52,229**	$4,054	$0	$10,733	**$67,016**	$108
12	INSTRUMENTATION & CONTROL	$9,358	$1,752	$6,282	$0	$0	**$17,391**	$1,436	$870	$3,296	**$22,992**	$37
13	IMPROVEMENTS TO SITE	$3,155	$1,860	$7,843	$0	$0	**$12,858**	$1,132	$0	$4,197	**$18,186**	$29
14	BUILDINGS & STRUCTURES	$0	$6,209	$7,240	$0	$0	**$13,449**	$1,095	$0	$2,378	**$16,922**	$27
	TOTAL COST	**$559,240**	**$59,898**	**$219,767**	**$0**	**$0**	**$838,905**	**$70,010**	**$27,220**	**$144,031**	**$1,080,166**	**$1,733**

Exhibit 3-63 Total Plant Cost Details

	Client:	USDOE/NETL								Report Date:	05-Apr-07		
	Project:	Bituminous Baseline Study											
		TOTAL PLANT COST SUMMARY											
	Case:	Case 03 - ConocoPhillips IGCC w/o CO2											
	Plant Size:	623.4 MW,net		Estimate Type:		Conceptual				Cost Base (Dec)	2006	($x1000)	
Acct No.	**Item/Description**	**Equipment Cost**	**Material Cost**	**Labor Direct**	**Labor Indirect**	**Sales Tax**	**Bare Erected Cost $**	**Eng'g CM H.O.& Fee**	**Contingencies Process**	**Contingencies Project**	**TOTAL PLANT COST $**	**TOTAL PLANT COST $/kW**	
1	COAL & SORBENT HANDLING												
1.1	Coal Receive & Unload	$3,430	$0	$1,693	$0	$0	$5,123	$411	$0	$1,107	$6,641	$11	
1.2	Coal Stackout & Reclaim	$4,432	$0	$1,086	$0	$0	$5,517	$433	$0	$1,190	$7,141	$11	
1.3	Coal Conveyors	$4,120	$0	$1,074	$0	$0	$5,195	$409	$0	$1,121	$6,724	$11	
1.4	Other Coal Handling	$1,078	$0	$249	$0	$0	$1,327	$104	$0	$286	$1,717	$3	
1.5	Sorbent Receive & Unload	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
1.6	Sorbent Stackout & Reclaim	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
1.7	Sorbent Conveyors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
1.8	Other Sorbent Handling	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
1.9	Coal & Sorbent Hnd.Foundations	$0	$2,435	$6,132	$0	$0	$8,566	$731	$0	$1,860	$11,157	$18	
	SUBTOTAL 1.	**$13,060**	**$2,435**	**$10,233**	**$0**	**$0**	**$25,728**	**$2,088**	**$0**	**$5,563**	**$33,379**	**$54**	
2	COAL & SORBENT PREP & FEED												
2.1	Coal Crushing & Drying incl w/2.3	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
2.2	Prepared Coal Storage & Feed	$1,462	$348	$232	$0	$0	$2,042	$157	$0	$440	$2,638	$4	
2.3	Slurry Prep & Feed	$19,945	$0	$8,962	$0	$0	$28,908	$2,310	$0	$6,244	$37,462	$60	
2.4	Misc.Coal Prep & Feed	$804	$582	$1,772	$0	$0	$3,158	$259	$0	$684	$4,101	$7	
2.5	Sorbent Prep Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
2.6	Sorbent Storage & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
2.7	Sorbent Injection System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
2.8	Booster Air Supply System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
2.9	Coal & Sorbent Feed Foundation	$0	$3,135	$2,592	$0	$0	$5,727	$473	$0	$1,240	$7,441	$12	
	SUBTOTAL 2.	**$22,211**	**$4,065**	**$13,559**	**$0**	**$0**	**$39,835**	**$3,200**	**$0**	**$8,607**	**$51,642**	**$83**	
3	FEEDWATER & MISC. BOP SYSTEMS												
3.1	FeedwaterSystem	$3,088	$5,369	$2,836	$0	$0	$11,293	$934	$0	$2,445	$14,672	$24	
3.2	Water Makeup & Pretreating	$502	$52	$280	$0	$0	$834	$71	$0	$271	$1,176	$2	
3.3	Other Feedwater Subsystems	$1,705	$578	$521	$0	$0	$2,804	$225	$0	$606	$3,634	$6	
3.4	Service Water Systems	$289	$590	$2,049	$0	$0	$2,928	$254	$0	$955	$4,137	$7	
3.5	Other Boiler Plant Systems	$1,553	$596	$1,478	$0	$0	$3,626	$305	$0	$786	$4,717	$8	
3.6	FO Supply Sys & Nat Gas	$299	$565	$527	$0	$0	$1,391	$119	$0	$302	$1,812	$3	
3.7	Waste Treatment Equipment	$697	$0	$427	$0	$0	$1,124	$98	$0	$367	$1,588	$3	
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	$1,015	$136	$526	$0	$0	$1,678	$145	$0	$547	$2,369	$4	
	SUBTOTAL 3.	**$9,148**	**$7,886**	**$8,644**	**$0**	**$0**	**$25,678**	**$2,149**	**$0**	**$6,278**	**$34,105**	**$55**	
4	GASIFIER & ACCESSORIES												
4.1	Gasifier, Syngas Cooler & Auxiliaries (E-GAS)	$90,425	$0	$55,527	$0	$0	$145,952	$11,971	$21,893	$26,972	$206,789	$332	
4.2	Syngas Cooling (w/ 4.1)	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0	
4.3	ASU/Oxidant Compression	$137,711	$0	w/equip.	$0	$0	$137,711	$11,743	$0	$14,945	$164,399	$264	
4.4	LT Heat Recovery & FG Saturation	$18,487	$0	$6,956	$0	$0	$25,443	$2,191	$0	$5,527	$33,160	$53	
4.5	Misc. Gasification Equipment w/4.1 & 4.2	w/4.1&4.2	$0	w/4.1&4.2	$0	$0	$0	$0	$0	$0	$0	$0	
4.6	Other Gasification Equipment	$0	$1,142	$465	$0	$0	$1,607	$137	$0	$349	$2,092	$3	
4.8	Major Component Rigging	w/4.1&4.2	$0	w/4.1&4.2	$0	$0	$0	$0	$0	$0	$0	$0	
4.9	Gasification Foundations	$0	$7,439	$4,275	$0	$0	$11,713	$957	$0	$3,168	$15,838	$25	
	SUBTOTAL 4.	**$246,624**	**$8,580**	**$67,222**	**$0**	**$0**	**$322,427**	**$26,999**	**$21,893**	**$50,961**	**$422,279**	**$677**	

Exhibit 3-63 Total Plant Cost Details (continued)

Client:	USDOE/NETL
Project:	Bituminous Baseline Study
Report Date:	05-Apr-07

TOTAL PLANT COST SUMMARY

Case:	Case 03 - ConocoPhillips IGCC w/o CO2
Plant Size:	623.4 MW,net
Estimate Type:	Conceptual
Cost Base (Dec)	2006
	($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5A	GAS CLEANUP & PIPING											
5A.1	MDEA-LT AGR	$34,245	$0	$16,003	$0	$0	$50,248	$4,291	$0	$10,908	$65,447	$105
5A.2	Elemental Sulfur Plant	$11,411	$2,265	$14,734	$0	$0	$28,410	$2,454	$0	$6,173	$37,037	$59
5A.3	Mercury Removal	$1,177	$0	$897	$0	$0	$2,074	$178	$104	$471	$2,827	$5
5A.4	COS Hydrolysis	$3,651	$0	$4,771	$0	$0	$8,422	$728	$0	$1,830	$10,980	$18
5A.5	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.6	Blowback Gas Systems	$410	$230	$130	$0	$0	$770	$65	$0	$167	$1,002	$2
5A.7	Fuel Gas Piping	$0	$1,161	$800	$0	$0	$1,961	$160	$0	$424	$2,546	$4
5A.9	HGCU Foundations	$0	$1,149	$746	$0	$0	$1,895	$155	$0	$615	$2,666	$4
	SUBTOTAL 5A.	**$50,895**	**$4,805**	**$38,080**	**$0**	**$0**	**$93,780**	**$8,032**	**$104**	**$20,588**	**$122,504**	**$197**
5B	CO2 REMOVAL & COMPRESSION											
5B.1	CO2 Removal System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5B.2	CO2 Compression & Drying	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 5B.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$82,000	$0	$5,071	$0	$0	$87,071	$7,338	$4,354	$9,876	$108,639	$174
6.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.3	Compressed Air Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.9	Combustion Turbine Foundations	$0	$684	$762	$0	$0	$1,446	$121	$0	$470	$2,037	$3
	SUBTOTAL 6.	**$82,000**	**$684**	**$5,833**	**$0**	**$0**	**$88,517**	**$7,459**	**$4,354**	**$10,346**	**$110,676**	**$178**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$33,926	$0	$4,828	$0	$0	$38,754	$3,277	$0	$4,203	$46,234	$74
7.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$0	$1,577	$1,143	$0	$0	$2,719	$214	$0	$587	$3,520	$6
7.4	Stack	$3,123	$0	$1,174	$0	$0	$4,296	$366	$0	$466	$5,129	$8
7.9	HRSG,Duct & Stack Foundations	$0	$622	$601	$0	$0	$1,223	$102	$0	$397	$1,722	$3
	SUBTOTAL 7.	**$37,049**	**$2,198**	**$7,745**	**$0**	**$0**	**$46,992**	**$3,959**	**$0**	**$5,653**	**$56,604**	**$91**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$28,109	$0	$4,930	$0	$0	$33,039	$2,837	$0	$3,588	$39,463	$63
8.2	Turbine Plant Auxiliaries	$198	$0	$455	$0	$0	$654	$57	$0	$71	$782	$1
8.3	Condenser & Auxiliaries	$4,660	$0	$1,421	$0	$0	$6,082	$517	$0	$660	$7,259	$12
8.4	Steam Piping	$5,233	$0	$3,687	$0	$0	$8,920	$682	$0	$2,400	$12,002	$19
8.9	TG Foundations	$0	$953	$1,621	$0	$0	$2,574	$217	$0	$837	$3,629	$6
	SUBTOTAL 8.	**$38,201**	**$953**	**$12,115**	**$0**	**$0**	**$51,268**	**$4,310**	**$0**	**$7,556**	**$63,135**	**$101**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$4,397	$0	$967	$0	$0	$5,364	$455	$0	$873	$6,692	$11
9.2	Circulating Water Pumps	$1,383	$0	$86	$0	$0	$1,469	$113	$0	$237	$1,819	$3
9.3	Circ.Water System Auxiliaries	$116	$0	$17	$0	$0	$132	$11	$0	$22	$165	$0
9.4	Circ.Water Piping	$0	$4,910	$1,253	$0	$0	$6,163	$489	$0	$1,330	$7,982	$13
9.5	Make-up Water System	$284	$0	$403	$0	$0	$688	$58	$0	$149	$895	$1
9.6	Component Cooling Water Sys	$579	$693	$490	$0	$0	$1,762	$146	$0	$382	$2,290	$4
9.9	Circ.Water System Foundations& Structures	$0	$1,699	$2,909	$0	$0	$4,608	$389	$0	$1,499	$6,497	$10
	SUBTOTAL 9.	**$6,760**	**$7,303**	**$6,124**	**$0**	**$0**	**$20,187**	**$1,661**	**$0**	**$4,492**	**$26,340**	**$42**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Slag Dewatering & Cooling	$15,861	$0	$7,828	$0	$0	$23,688	$2,024	$0	$2,571	$28,283	$45
10.2	Gasifier Ash Depressurization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.3	Cleanup Ash Depressurization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.4	High Temperature Ash Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.5	Other Ash Rrecovery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$523	$0	$569	$0	$0	$1,092	$94	$0	$178	$1,365	$2
10.7	Ash Transport & Feed Equipment	$706	$0	$169	$0	$0	$876	$72	$0	$142	$1,090	$2
10.8	Misc. Ash Handling Equipment	$1,083	$1,327	$397	$0	$0	$2,807	$238	$0	$457	$3,502	$6
10.9	Ash/Spent Sorbent Foundation	$0	$46	$58	$0	$0	$104	$9	$0	$34	$147	$0
	SUBTOTAL 10.	**$18,173**	**$1,373**	**$9,021**	**$0**	**$0**	**$28,568**	**$2,437**	**$0**	**$3,382**	**$34,386**	**$55**

Exhibit 3-63 Total Plant Cost Details (continued)

	Client:	USDOE/NETL								Report Date:	05-Apr-07		
	Project:	Bituminous Baseline Study											
				TOTAL PLANT COST SUMMARY									
	Case:	Case 03 - ConocoPhillips IGCC w/o CO2											
	Plant Size:	623.4 MW,net		Estimate Type:		Conceptual				Cost Base (Dec)	2006	($x1000)	

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$901	$0	$899	$0	$0	$1,800	$153	$0	$195	$2,148	$3
11.2	Station Service Equipment	$3,498	$0	$328	$0	$0	$3,827	$326	$0	$415	$4,568	$7
11.3	Switchgear & Motor Control	$6,686	$0	$1,226	$0	$0	$7,911	$657	$0	$1,285	$9,853	$16
11.4	Conduit & Cable Tray	$0	$3,181	$10,327	$0	$0	$13,508	$1,157	$0	$3,666	$18,331	$29
11.5	Wire & Cable	$0	$5,842	$3,930	$0	$0	$9,772	$640	$0	$2,603	$13,015	$21
11.6	Protective Equipment	$0	$624	$2,365	$0	$0	$2,989	$262	$0	$488	$3,739	$6
11.7	Standby Equipment	$215	$0	$218	$0	$0	$433	$37	$0	$71	$541	$1
11.8	Main Power Transformers	$11,308	$0	$138	$0	$0	$11,446	$776	$0	$1,833	$14,056	$23
11.9	Electrical Foundations	$0	$149	$394	$0	$0	$543	$46	$0	$177	$766	$1
	SUBTOTAL 11.	**$22,608**	**$9,796**	**$19,825**	**$0**	**$0**	**$52,229**	**$4,054**	**$0**	**$10,733**	**$67,016**	**$108**
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
12.3	Steam Turbine Control	w/8.1	$0	w/8.1	$0	$0	$0	$0	$0	$0	$0	$0
12.4	Other Major Component Control	$924	$0	$643	$0	$0	$1,566	$135	$78	$267	$2,047	$3
12.5	Signal Processing Equipment	W/12.7	$0	W/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.6	Control Boards,Panels & Racks	$212	$0	$142	$0	$0	$354	$31	$18	$80	$483	$1
12.7	Computer & Accessories	$4,928	$0	$164	$0	$0	$5,092	$432	$255	$578	$6,357	$10
12.8	Instrument Wiring & Tubing	$0	$1,752	$3,666	$0	$0	$5,418	$412	$271	$1,525	$7,626	$12
12.9	Other I & C Equipment	$3,294	$0	$1,666	$0	$0	$4,960	$426	$248	$845	$6,480	$10
	SUBTOTAL 12.	**$9,358**	**$1,752**	**$6,282**	**$0**	**$0**	**$17,391**	**$1,436**	**$870**	**$3,296**	**$22,992**	**$37**
13	Improvements to Site											
13.1	Site Preparation	$0	$99	$2,132	$0	$0	$2,231	$197	$0	$728	$3,156	$5
13.2	Site Improvements	$0	$1,761	$2,357	$0	$0	$4,118	$362	$0	$1,344	$5,824	$9
13.3	Site Facilities	$3,155	$0	$3,354	$0	$0	$6,509	$572	$0	$2,124	$9,206	$15
	SUBTOTAL 13.	**$3,155**	**$1,860**	**$7,843**	**$0**	**$0**	**$12,858**	**$1,132**	**$0**	**$4,197**	**$18,186**	**$29**
14	Buildings & Structures											
14.1	Combustion Turbine Area	$0	$221	$127	$0	$0	$348	$27	$0	$75	$451	$1
14.2	Steam Turbine Building	$0	$2,309	$3,334	$0	$0	$5,643	$464	$0	$916	$7,024	$11
14.3	Administration Building	$0	$793	$583	$0	$0	$1,375	$110	$0	$223	$1,708	$3
14.4	Circulation Water Pumphouse	$0	$156	$84	$0	$0	$240	$19	$0	$39	$298	$0
14.5	Water Treatment Buildings	$0	$399	$395	$0	$0	$794	$64	$0	$129	$987	$2
14.6	Machine Shop	$0	$406	$281	$0	$0	$687	$55	$0	$111	$853	$1
14.7	Warehouse	$0	$655	$428	$0	$0	$1,083	$86	$0	$175	$1,345	$2
14.8	Other Buildings & Structures	$0	$392	$310	$0	$0	$702	$56	$0	$152	$910	$1
14.9	Waste Treating Building & Str.	$0	$877	$1,698	$0	$0	$2,575	$214	$0	$558	$3,348	$5
	SUBTOTAL 14.	**$0**	**$6,209**	**$7,240**	**$0**	**$0**	**$13,449**	**$1,095**	**$0**	**$2,378**	**$16,922**	**$27**
	TOTAL COST	**$559,240**	**$59,898**	**$219,767**	**$0**	**$0**	**$838,905**	**$70,010**	**$27,220**	**$144,031**	**$1,080,166**	**$1,733**

Exhibit 3-64 Case 3 Initial and Annual Operating and Maintenance Costs

INITIAL & ANNUAL O&M EXPENSES						Cost Base (Dec)	2006
Case 03 - ConocoPhillips 600MW IGCC w/o CO2						Heat Rate-net(Btu/kWh):	8,681
						MWe-net:	623
						Capacity Factor: (%):	80
OPERATING & MAINTENANCE LABOR							
Operating Labor							
Operating Labor Rate(base):	33.00	$/hour					
Operating Labor Burden:	30.00	% of base					
Labor O-H Charge Rate:	25.00	% of labor					
			Total				
Skilled Operator	2.0		2.0				
Operator	9.0		9.0				
Foreman	1.0		1.0				
Lab Tech's, etc.	3.0		3.0				
TOTAL-O.J.'s	15.0		15.0				
						Annual Cost $	Annual Unit Cost $/kW-net
Annual Operating Labor Cost						$5,637,060	$9.043
Maintenance Labor Cost						$11,924,540	$19.129
Administrative & Support Labor						$4,390,400	$7.043
TOTAL FIXED OPERATING COSTS						**$21,951,999**	**$35.215**
VARIABLE OPERATING COSTS							
							$/kWh-net
Maintenance Material Cost						**$22,346,706**	**$0.00512**
Consumables	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost			
Water(/1000 gallons)	0	5,410.08	1.03	**$0**		**$1,627,136**	**$0.00037**
Chemicals							
MU & WT Chem.(lb)	112,811	16,116	0.16	$18,591		$775,520	$0.00018
Carbon (Mercury Removal) (lb)	84,449	116	1.00	$84,449		$33,872	$0.00001
COS Catalyst (m3)	375	0.26	2,308.40	$865,651		$173,030	$0.00004
Water Gas Shift Catalyst(ft3)	0	0	475.00	$0		$0	$0.00000
Selexol Solution (gal.)	0	0	12.90	$0		$0	$0.00000
MDEA Solution (gal)	280	40	8.38	$2,345		$97,820	$0.00002
Sulfinol Solution (gal)	0	0	9.68	$0		$0	$0.00000
SCR Catalyst (m3)	0	0	0.00	$0		$0	$0.00000
Aqueous Ammonia (ton)	0	0	0.00	$0		$0	$0.00000
Claus Catalyst(ft3)	w/equip.	2.10	125.00	$0		$76,650	$0.00002
Subtotal Chemicals				**$971,037**		**$1,156,892**	**$0.00026**
Other							
Supplemental Fuel(MBtu)	0	0	0.00	$0		$0	$0.00000
Gases,N2 etc.(/100scf)	0	0	0.00	$0		$0	$0.00000
L.P. Steam(/1000 pounds)	0	0	0.00	$0		$0	$0.00000
Subtotal Other				**$0**		**$0**	**$0.00000**
Waste Disposal							
Spent Mercury Catalyst (lb)	0	116	0.40	$0		$13,603	$0.00000
Flyash (ton)	0	0	0.00	$0		$0	$0.00000
Bottom Ash(ton)	0	566	15.45	$0		$2,555,311	$0.00058
Subtotal-Waste Disposal				**$0**		**$2,568,914**	**$0.00059**
By-products & Emissions							
Sulfur(tons)	0	139	0.00	$0		$0	$0.00000
Subtotal By-Products				**$0**		**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$971,037**		**$27,699,648**	**$0.00634**
Fuel(ton)	166,992	5,566	42.11	**$7,032,052**		**$68,445,302**	**$0.01567**

3.3.8 CASE 4 - E-GAS™ IGCC POWER PLANT WITH CO_2 CAPTURE

This case is configured to produce electric power with CO_2 capture. The plant configuration is the same as Case 3, namely two gasifier trains, two advanced F class turbines, two HRSGs and one steam turbine. The gross power output from the plant is constrained by the capacity of the two combustion turbines, and since the CO_2 capture and compression process increases the auxiliary load on the plant, the net output is significantly reduced relative to Case 3.

The process description for Case 4 is similar to Case 2 with several notable exceptions to accommodate CO_2 capture. A BFD and stream tables for Case 4 are shown in Exhibit 3-65 and Exhibit 3-66, respectively. Instead of repeating the entire process description, only differences from Case 3 are reported here.

Coal Preparation and Feed Systems

No differences from Case 3.

Gasification

The gasification process is the same as Case 3 with the exception that total coal feed to the two gasifiers is 5,203 tonnes/day (5,735 TPD) (stream 6) and the ASU provides 4,000 tonnes/day (4,420 TPD) of 95 mole percent oxygen to the gasifier and Claus plant (streams 5 and 3).

Raw Gas Cooling/Particulate Removal

Raw gas cooling and particulate removal are the same as Case 3 with the exception that approximately 483,170 kg/h (1,065,206 lb/h) of saturated steam at 13.8 MPa (2,000 psia) is generated in the SGC.

Syngas Scrubber/Sour Water Stripper

No differences from Case 3.

Sour Gas Shift (SGS)

The SGS process was described in Section 3.1.3. In Case 4 steam (stream 8) is added to the syngas exiting the scrubber to adjust the H_2O:CO molar ratio to approximately 2:1 prior to the first WGS reactor. The hot syngas exiting the first stage of SGS is used to generate a portion of the steam that is added in stream 8. Two more stages of SGS (for a total of three) result in 97.6 percent overall conversion of the CO to CO_2. The syngas exiting the final stage of SGS still contains 2.4 vol% CH_4 which is subsequently oxidized to CO_2 in the CT and limits overall carbon capture to 88.4 percent. The warm syngas from the second stage of SGS is cooled to 232°C (450°F) by producing IP steam that is sent to the reheater in the HRSG. The SGS catalyst also serves to hydrolyze COS thus eliminating the need for a separate COS hydrolysis reactor. Following the third stage of SGS, the syngas is further cooled to 35°C (95°F) prior to the mercury removal beds.

Mercury Removal and Acid Gas Removal

Mercury removal is the same as in Case 3.

Exhibit 3-65 Case 4 Process Flow Diagram, E-Gas™ IGCC with CO_2 Capture

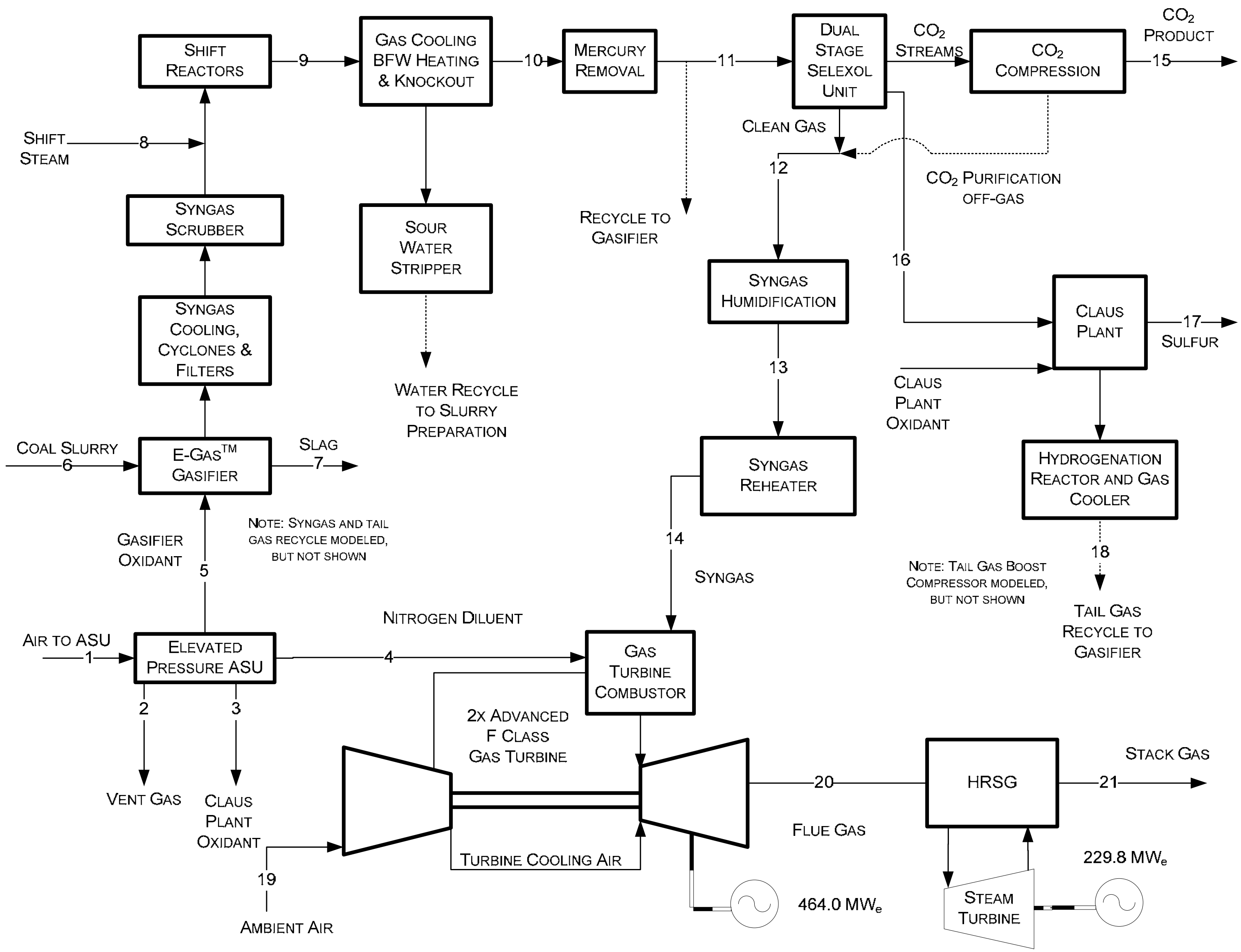

Exhibit 3-66 Case 4 Stream Table, E-Gas™ IGCC with CO_2 Capture

	1	2	3	4	5	6[A]	7	8	9	10	11
V-L Mole Fraction											
Ar	0.0092	0.0263	0.0360	0.0023	0.0320	0.0000	0.0000	0.0000	0.0051	0.0065	0.0065
CH_4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0238	0.0302	0.0302
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0052	0.0067	0.0067
CO_2	0.0003	0.0092	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3214	0.4122	0.4122
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.4116	0.5275	0.5275
H_2O	0.0099	0.2713	0.0000	0.0004	0.0000	1.0000	0.0000	1.0000	0.2185	0.0014	0.0014
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0051	0.0058	0.0058
N_2	0.7732	0.4665	0.0140	0.9919	0.0180	0.0000	0.0000	0.0000	0.0073	0.0094	0.0094
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0019	0.0004	0.0004
O_2	0.2074	0.2266	0.9500	0.0054	0.9500	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	55,654	1,969	278	41,984	11,156	25,799	0	31,642	91,106	71,043	56,835
V-L Flowrate (lb/hr)	1,606,000	52,498	8,944	1,178,060	359,031	249,436	0	570,044	1,827,120	1,465,320	1,172,260
Solids Flowrate (lb/hr)	0	0	0	0	0	424,717	48,622	0	0	0	0
Temperature (°F)	242	70	90	385	191	140	1,850	615	457	93	93
Pressure (psia)	190.0	16.4	125.0	460.0	740.0	850.0	850.0	600.0	516.0	481.0	471.0
Enthalpy (BTU/lb)[B]	57.3	26.7	12.5	88.0	34.4	---	1,120	1300.1	384.8	24.1	24.1
Density (lb/ft^3)	0.729	0.103	0.683	1.424	3.412	---	---	0.937	1.052	1.672	1.638
Molecular Weight	28.86	26.67	32.23	28.06	32.18	---	---	18.02	20.05	20.63	20.63

A - Solids flowrate includes dry coal; V-L flowrate includes slurry water and water from coal

B - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 3-66 Case 4 Stream Table (Continued)

	12	13	14	15	16	17	18	19	20	21
V-L Mole Fraction										
Ar	0.0109	0.0093	0.0093	0.0000	0.0000	0.0000	0.0205	0.0094	0.0089	0.0089
CH_4	0.0508	0.0436	0.0436	0.0000	0.0000	0.0000	0.0880	0.0000	0.0000	0.0000
CO	0.0112	0.0096	0.0096	0.0000	0.0000	0.0000	0.0003	0.0000	0.0000	0.0000
CO_2	0.0243	0.0208	0.0208	1.0000	0.4321	0.0000	0.6024	0.0003	0.0097	0.0097
COS	0.0000	0.0000	0.0000	0.0000	0.0004	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.8888	0.7620	0.7620	0.0000	0.0000	0.0000	0.0215	0.0000	0.0000	0.0000
H_2O	0.0001	0.1427	0.1427	0.0000	0.0554	0.0000	0.0006	0.0108	0.1350	0.1350
H_2S	0.0000	0.0000	0.0000	0.0000	0.4035	0.0000	0.0180	0.0000	0.0000	0.0000
N_2	0.0139	0.0119	0.0119	0.0000	0.0774	0.0000	0.2486	0.7719	0.7429	0.7429
NH_3	0.0000	0.0000	0.0000	0.0000	0.0312	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2076	0.1035	0.1035
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	33,733	39,346	39,346	22,257	813	47	628	242,512	308,662	308,662
V-L Flowrate (lb/hr)	162,487	263,603	263,603	979,537	29,677	11,954	22,868	6,996,340	8,438,000	8,438,000
Solids Flowrate (lb/hr)	0	0	0	0	0	11,954	0	0	0	0
Temperature (°F)	99	299	385	156	120	375	95	59	1052	270
Pressure (psia)	468.5	458.5	453.5	2214.7	30.5	25.4	767.5	14.7	15.2	15.2
Enthalpy (BTU/lb)[B]	97.3	699.4	795.2	-46.0	48.7	-96.2	14.5	13.8	372.8	157.8
Density (lb/ft^3)	0.376	0.378	0.335	30.793	0.179	---	4.692	0.076	0.026	0.053
Molecular Weight	4.82	6.70	6.70	44.01	36.49	---	36.39	28.85	27.34	27.34

B - Reference conditions are 32.02 F & 0.089 PSIA

The AGR process in Case 4 is a two stage Selexol process where H_2S is removed in the first stage and CO_2 in the second stage of absorption as previously described in Section 3.1.5. The process results in three product streams, the clean syngas, a CO_2-rich stream and an acid gas feed to the Claus plant. The acid gas (stream 16) contains 40 percent H_2S and 43 percent CO_2 with the balance primarily N_2. The CO_2-rich stream is discussed further in the CO_2 compression section.

CO_2 Compression and Dehydration

CO_2 from the AGR process is generated at three pressure levels. The LP stream is compressed from 0.15 MPa (22 psia) to 1.1 MPa (160 psia) and then combined with the MP stream. The HP stream is combined between compressor stages at 2.1 MPa (300 psia). The combined stream is compressed from 2.1 MPa (300 psia) to a supercritical condition at 15.3 MPa (2215 psia) using a multiple-stage, intercooled compressor. During compression, the CO_2 stream is dehydrated to a dewpoint of -40ºC (-40°F) with triethylene glycol. The raw CO_2 stream from the Selexol process contains over 93 percent CO_2 with the balance primarily nitrogen. For modeling purposes it was assumed that the impurities were separated from the CO_2 and combined with the clean syngas stream from the Selexol process. The pure CO_2 (stream 15) is transported to the plant fence line and is sequestration ready. CO_2 TS&M costs were estimated using the methodology described in Section 2.7.

Claus Unit

The Claus plant is the same as Case 3 with the following exceptions:

- 5,423 kg/h (11,955 lb/h) of sulfur (stream 17) are produced
- The waste heat boiler generates 17,296 kg/h (38,131 lb/h) of 4.0 MPa (585 psia) steam, which provides all of the Claus plant process needs and provides some additional steam to the medium pressure steam header.

Power Block

Clean syngas from the AGR plant is combined with a small amount of clean gas from the CO_2 compression process (stream 12) and partially humidified because the nitrogen available from the ASU is insufficient to provide adequate dilution. The moisturized syngas is reheated (stream 14) to 196°C (385°F) using HP boiler feedwater, diltuted with nitrogen (stream 4), and then enters the CT burner. There is no integration between the CT and the ASU in this case. The exhaust gas (stream 20) exits the CT at 567°C (1052°F) and enters the HRSG where additional heat is recovered. The flue gas exits the HRSG at 132°C (270°F) (stream 21) and is discharged through the plant stack. The steam raised in the HRSG is used to power an advanced commercially available steam turbine using a 12.4 MPa/538°C/538°C (1800 psig/1000°F/1000°F) steam cycle.

Air Separation Unit

The elevated pressure ASU is the same as in other cases and produces 4,000 tonnes/day (4,420 TPD) of 95 mole percent oxygen and 12,830 tonnes/day (14,140 TPD) of nitrogen. There is no integration between the ASU and the combustion turbine.

3.3.9 CASE 4 PERFORMANCE RESULTS

The Case 4 modeling assumptions were presented previously in Section 3.3.3.

The plant produces a net output of 518 MWe at a net plant efficiency of 31.7 percent (HHV basis). Overall performance for the entire plant is summarized in Exhibit 3-67 which includes auxiliary power requirements. The ASU accounts for nearly 62 percent of the auxiliary load between the main air compressor, the nitrogen compressor, the oxygen compressor and ASU auxiliaries. The two-stage Selexol process and CO_2 compression account for an additional 23 percent of the auxiliary power load. The BFW pumps and cooling water system (circulating water pumps and cooling tower fan) comprise nearly 6 percent of the load, leaving 9 percent of the auxiliary load for all other systems.

Exhibit 3-67 Case 4 Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine Power	464,000
Steam Turbine Power	229,840
TOTAL POWER, kWe	**693,840**
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	440
Coal Milling	2,230
Coal Slurry Pumps	580
Slag Handling and Dewatering	1,140
Air Separation Unit Auxiliaries	1,000
Air Separation Unit Main Air Compressor	62,760
Oxygen Compressor	8,490
Nitrogen Compressor	36,330
Syngas Recycle Blower	3,400
Tail Gas Recycle Blower	1,090
CO_2 Compressor	25,970
Boiler Feedwater Pumps	5,340
Condensate Pump	270
Flash Bottoms Pump	200
Circulating Water Pumps	3,020
Cooling Tower Fans	1,560
Scrubber Pumps	70
Double Stage Selexol Unit Auxiliaries	14,840
Gas Turbine Auxiliaries	1,000
Steam Turbine Auxiliaries	100
Claus Plant/TGTU Auxiliaries	200
Miscellaneous Balance of Plant (Note 1)	3,000
Transformer Loss	2,570
TOTAL AUXILIARIES, kWe	**175,600**
NET POWER, kWe	**518,240**
Net Plant Efficiency, % (HHV)	31.7
Net Plant Heat Rate (Btu/kWh)	10,757
CONDENSER COOLING DUTY 10^6 kJ/h (10^6 Btu/h)	**1,224 (1,161)**
CONSUMABLES	
As-Received Coal Feed, kg/h (lb/h)	216,752 (477,855)
Thermal Input, kWt	1,633,771
Raw Water Usage, m^3/min (gpm)	15.6 (4,135)

Note 1: Includes plant control systems, lighting, HVAC and miscellaneous low voltage loads

Environmental Performance

The environmental targets for emissions of Hg, NO_X, SO_2, CO_2 and particulate matter were presented in Section 2.4. A summary of the plant air emissions for Case 4 is presented in Exhibit 3-68.

Exhibit 3-68 Case 4 Air Emissions

	kg/GJ ($lb/10^6$ Btu)	Tonne/year (tons/year) 80% capacity factor	kg/MWh (lb/MWh)
SO_2	0.004 (0.0085)	151 (167)	0.031 (0.069)
NO_X	0.021 (0.050)	882 (972)	0.181 (0.400)
Particulates	0.003 (0.0071)	126 (139)	0.026 (0.057)
Hg	$0.25x10^{-6}$ ($0.57x10^{-6}$)	0.010 (0.011)	$2.1x10^{-6}$ ($4.6x10^{-6}$)
CO_2	10.1 (23.6)	417,000 (460,000)	86 (189)
CO_2[1]			115 (253)

[1] CO_2 emissions based on net power instead of gross power

The low level of SO_2 emissions is achieved by capture of the sulfur in the gas by the two-stage Selexol AGR process. The CO_2 capture target results in the sulfur compounds being removed to a greater extent than required in the environmental targets of Section 2.4. The clean syngas exiting the AGR process has a sulfur concentration of approximately 22 ppmv. This results in a concentration in the flue gas of less than 3 ppmv. The H_2S-rich regeneration gas from the AGR system is fed to a Claus plant, producing elemental sulfur. The Claus plant tail gas is hydrogenated to convert all sulfur species to H_2S, and then recycled back to the gasifier, thereby eliminating the need for a tail gas treatment unit.

NO_X emissions are limited by the use of humidification and nitrogen dilution to 15 ppmvd (NO_2 @ 15 percent O_2). Ammonia in the syngas is removed with process condensate prior to the low-temperature AGR process and ultimately destroyed in the Claus plant burner. This helps lower NO_X levels as well.

Particulate discharge to the atmosphere is limited to extremely low values by the use of a cyclone and a barrier filter in addition to the syngas scrubber and the gas washing effect of the AGR absorber. The particulate emissions represent filterable particulate only.

Ninety five percent of mercury is captured from the syngas by an activated carbon bed. Ninety five percent of the CO_2 from the syngas is captured in the AGR system and compressed for sequestration. Because of the relatively high CH_4 content in the syngas, this results in an overall carbon removal of 88.4 percent.

The carbon balance for the plant is shown in Exhibit 3-69. The carbon input to the plant consists of carbon in the air in addition to carbon in the coal. Carbon in the air is not neglected in the carbon balance below since the Aspen model accounts for air components throughout. Carbon leaves the plant as unburned carbon in the slag, as dissolved CO_2 in the wastewater blowdown stream, and CO_2 in the stack gas, ASU vent gas and the captured CO_2 product. Carbon in the wastewater blowdown stream is calculated by difference to close the material balance. The carbon capture efficiency is defined as the amount of carbon in the CO_2 product stream relative to the amount of carbon in the coal less carbon contained in the slag, represented by the following fraction:

(Carbon in Product for Sequestration)/[(Carbon in the Coal)-(Carbon in Slag)] or
267,147/(304,632-2,285) *100 or
88.4 percent

Exhibit 3-69 Case 4 Carbon Balance

Carbon In, kg/hr (lb/hr)		Carbon Out, kg/hr (lb/hr)	
Coal	138,180 (304,632)	**Slag**	1,037 (2,285)
Air (CO_2)	488 (1,077)	**Stack Gas**	16,246 (35,817)
		CO_2 Product	121,176 (267,147)
		ASU Vent	99 (218)
		Wastewater	110 (242)
Total	138,668 (305,709)	**Total**	138,668 (305,709)

Exhibit 3-70 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered in the Claus plant, dissolved SO_2 in the wastewater blowdown stream, and sulfur emitted in the stack gas. Sulfur in the slag is considered to be negligible, and the sulfur content of the blowdown stream is calculated by difference to close the material balance. The total sulfur capture is represented by the following fraction:

(Sulfur byproduct/Sulfur in the coal) or
(11,954/11,994) or
99.7 percent

Exhibit 3-70 Case 4 Sulfur Balance

Sulfur In, kg/hr (lb/hr)		Sulfur Out, kg/hr (lb/hr)	
Coal	5,440 (11,994)	**Elemental Sulfur**	5,422 (11,954)
		Stack Gas	11 (24)
		Wastewater	7 (16)
Total	5,440 (11,994)	**Total**	5,440 (11,994)

Exhibit 3-71 shows the overall water balance for the plant. Raw water is obtained from groundwater (50 percent) and from municipal sources (50 percent). Water demand represents the total amount of water required for a particular process. Some water is recovered within the process, primarily as syngas condensate, and that water is re-used as internal recycle. Raw water makeup is the difference between water demand and internal recycle.

Exhibit 3-71 Case 4 Water Balance

Water Use	Water Demand, m^3/min (gpm)	Internal Recycle, m^3/min (gpm)	Raw Water Makeup, m^3/min (gpm)
Slurry	1.5 (392)	1.5 (392)	0
Slag Handling	0.5 (126)	0.5 (126)	0
Humidifier	0.8 (219)	0.8 (219)	0
Shift Steam	4.3 (1,140)	0	4.3 (1,140)
BFW Makeup	0.2 (46)	0	0.2 (46)
Cooling Tower Makeup	11.7 (3,098)	0.6 (149)	11.1 (2,949)
Total	**19.0 (5,021)**	**3.4 (886)**	**15.6 (4,135)**

Heat and Mass Balance Diagrams

Heat and mass balance diagrams are shown for the following subsystems in Exhibit 3-72 through Exhibit 3-76:

- Coal gasification and air separation unit
- Syngas cleanup
- Sulfur recovery and tail gas recycle
- Combined cycle power generation
- Steam and feedwater

An overall plant energy balance is provided in tabular form in Exhibit 3-77. The power out is the combined combustion turbine and steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 3-67) is calculated by multiplying the power out by a combined generator efficiency of 98.4 percent.

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Exhibit 3-72 Case 4 Coal Gasification and Air Separation Unit Heat and Mass Balance Schematic

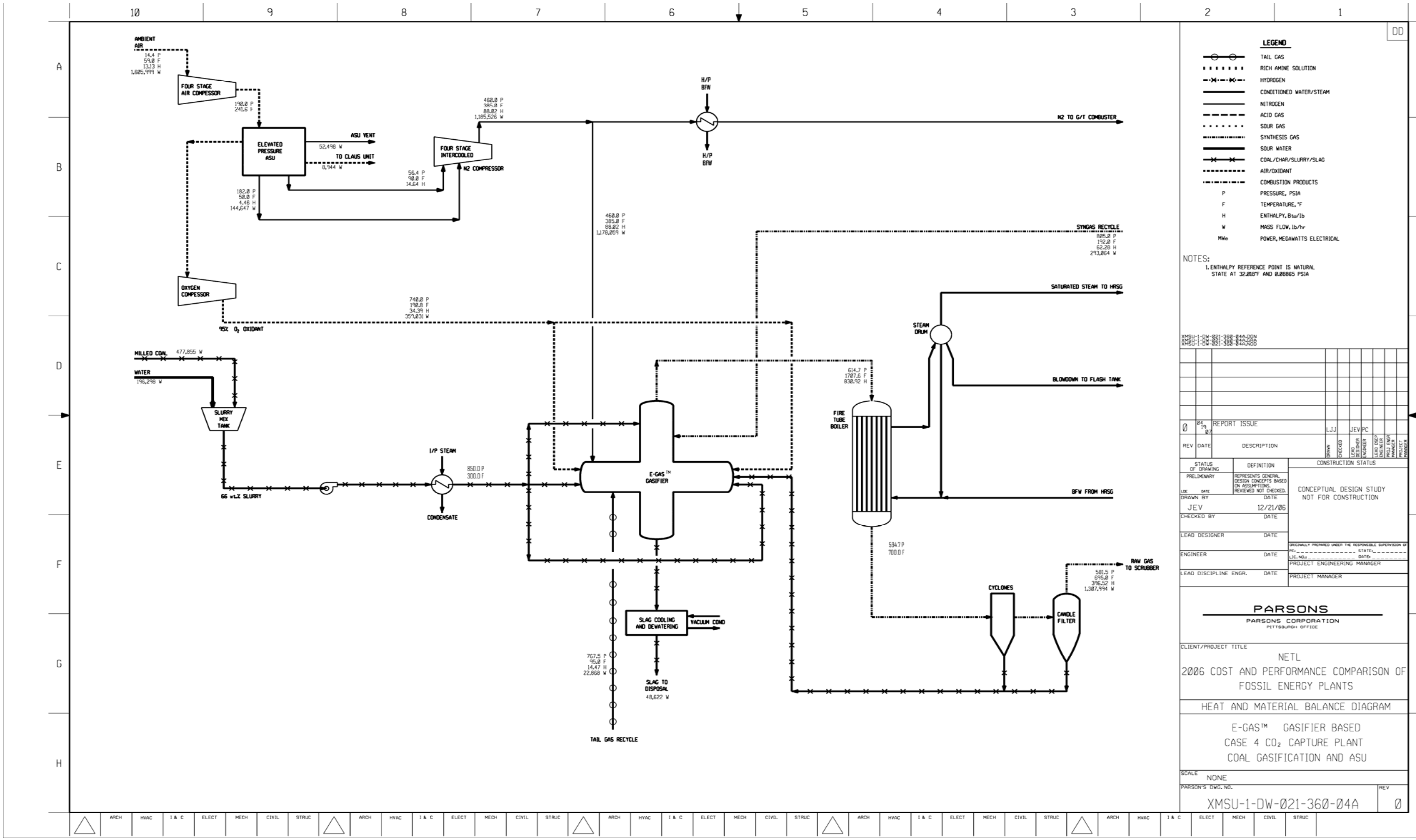

Exhibit 3-73 Case 4 Syngas Cleanup Heat and Mass Balance Schematic

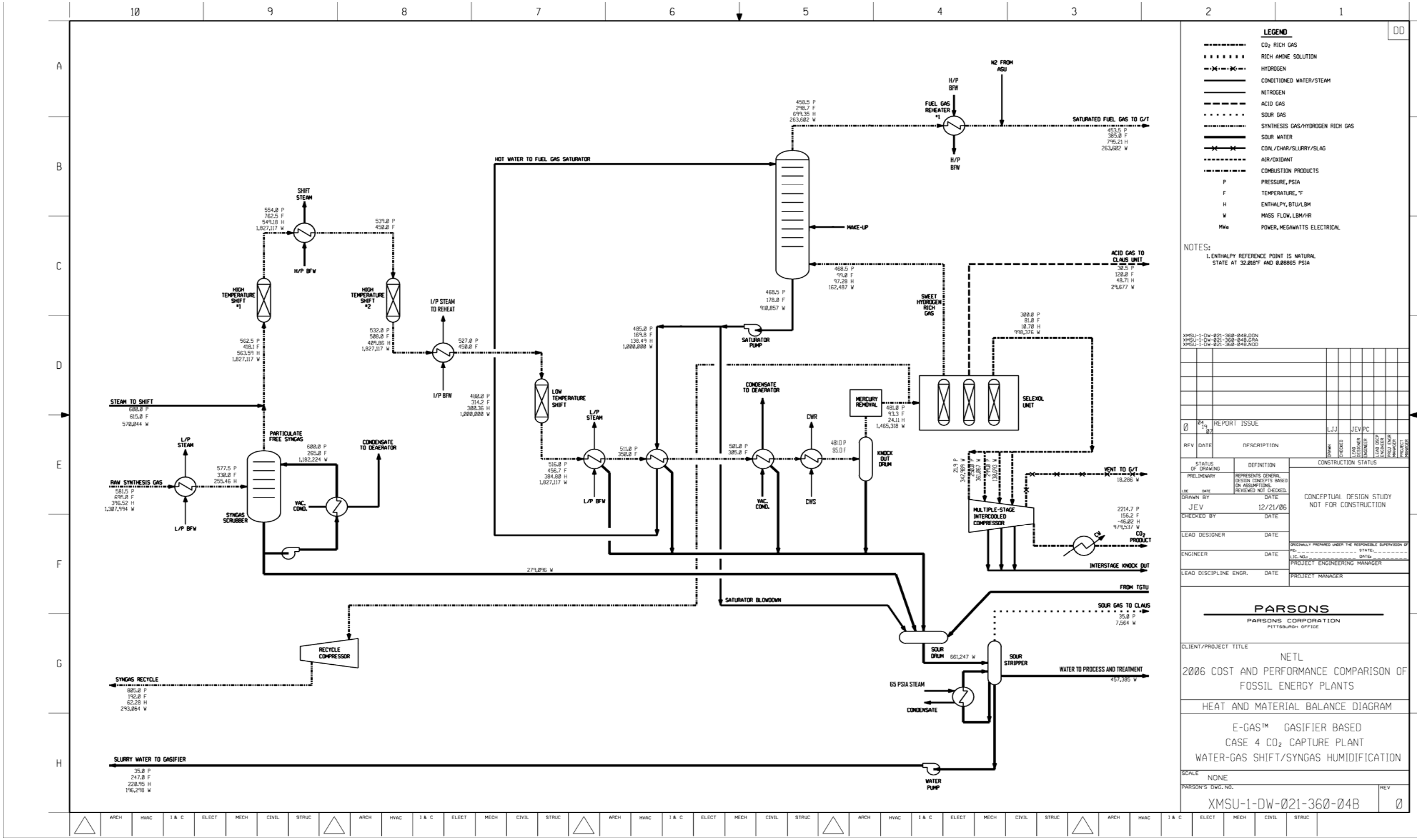

Exhibit 3-74 Case 4 Sulfur Recover and Tail Gas Recycle Heat and Mass Balance Schematic

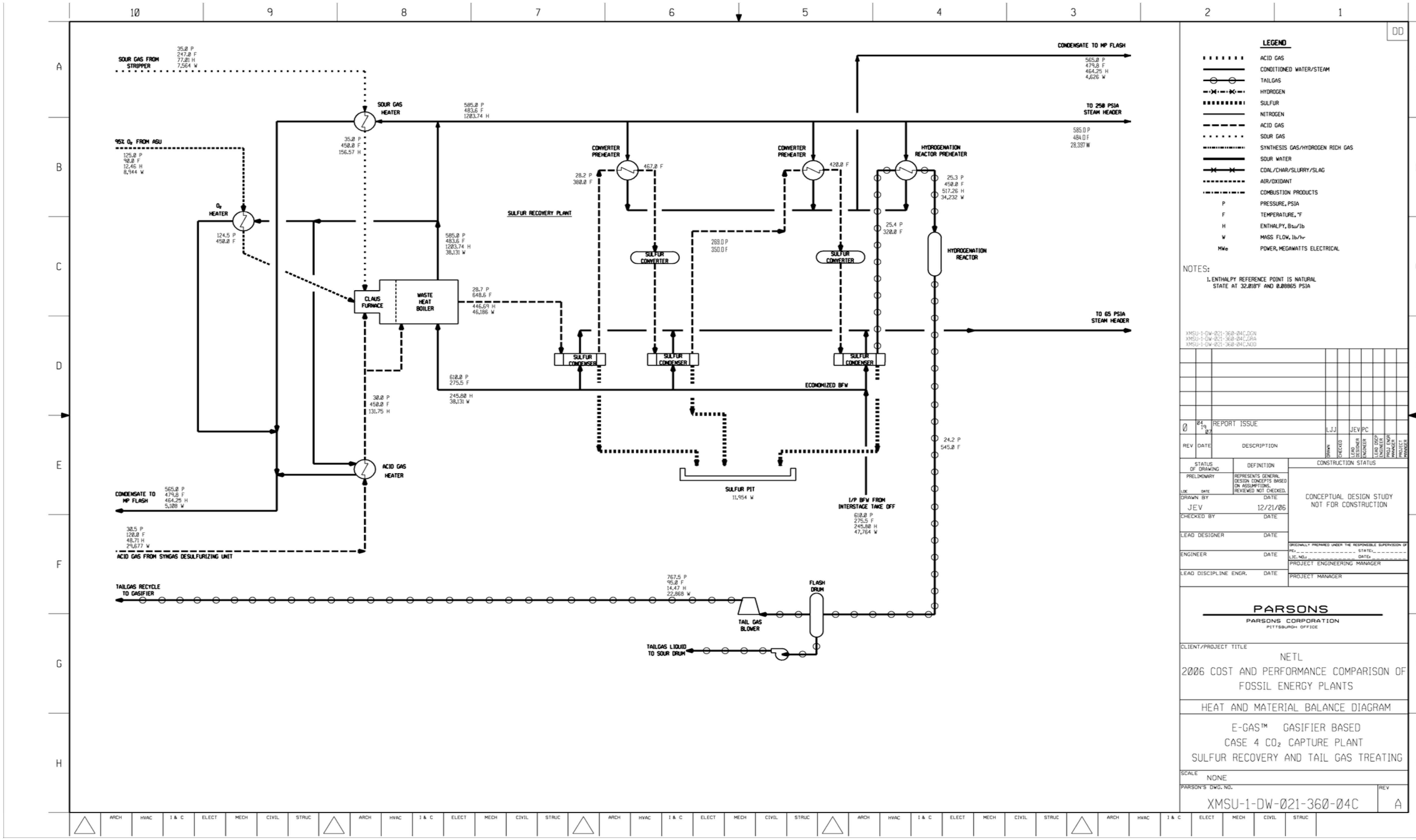

Exhibit 3-75 Case 4 Combined Cycle Power Generation Heat and Mass Balance Schematic

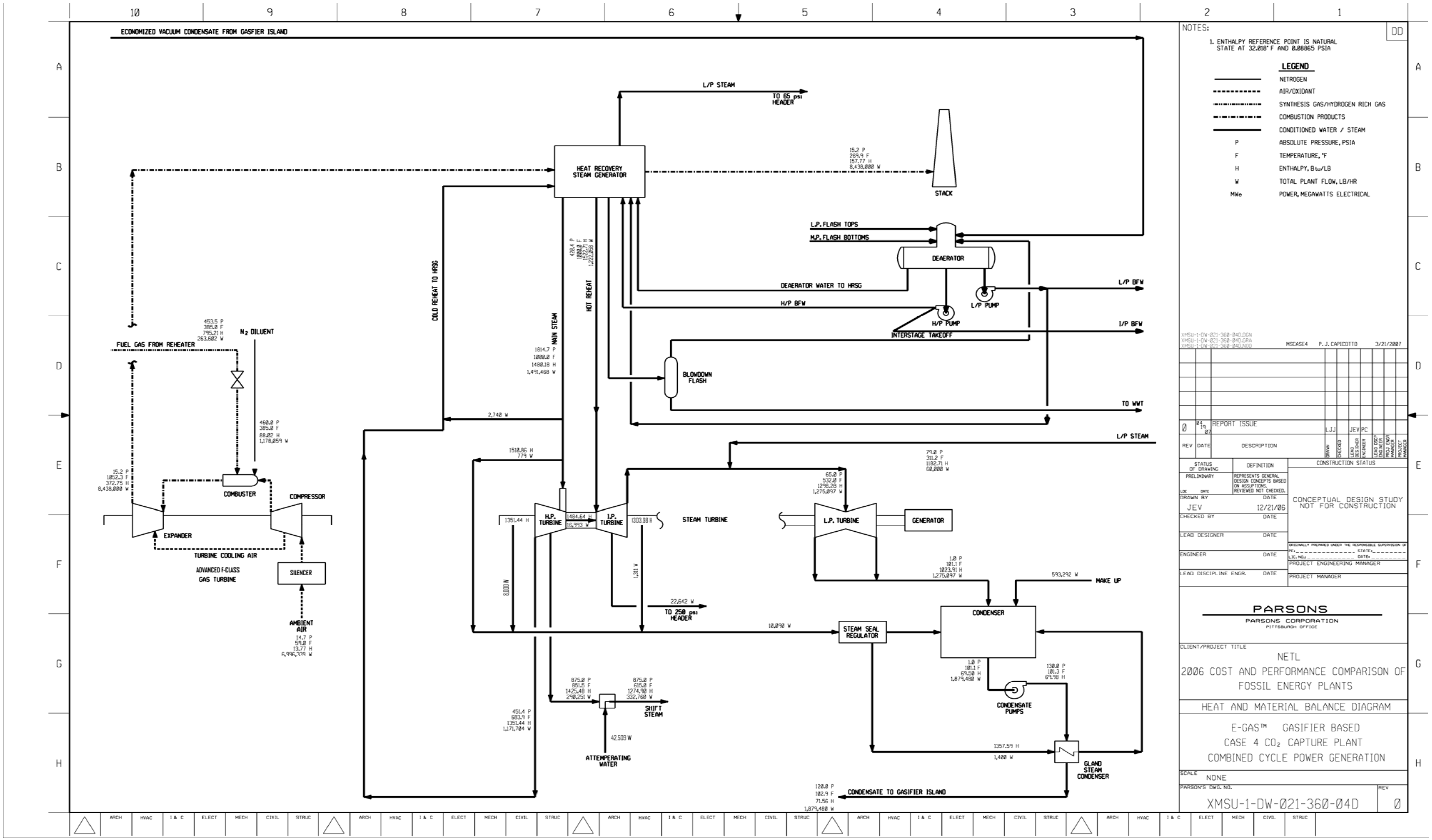

Exhibit 3-76 Case 4 Steam and Feedwater Heat and Mass Balance Schematic

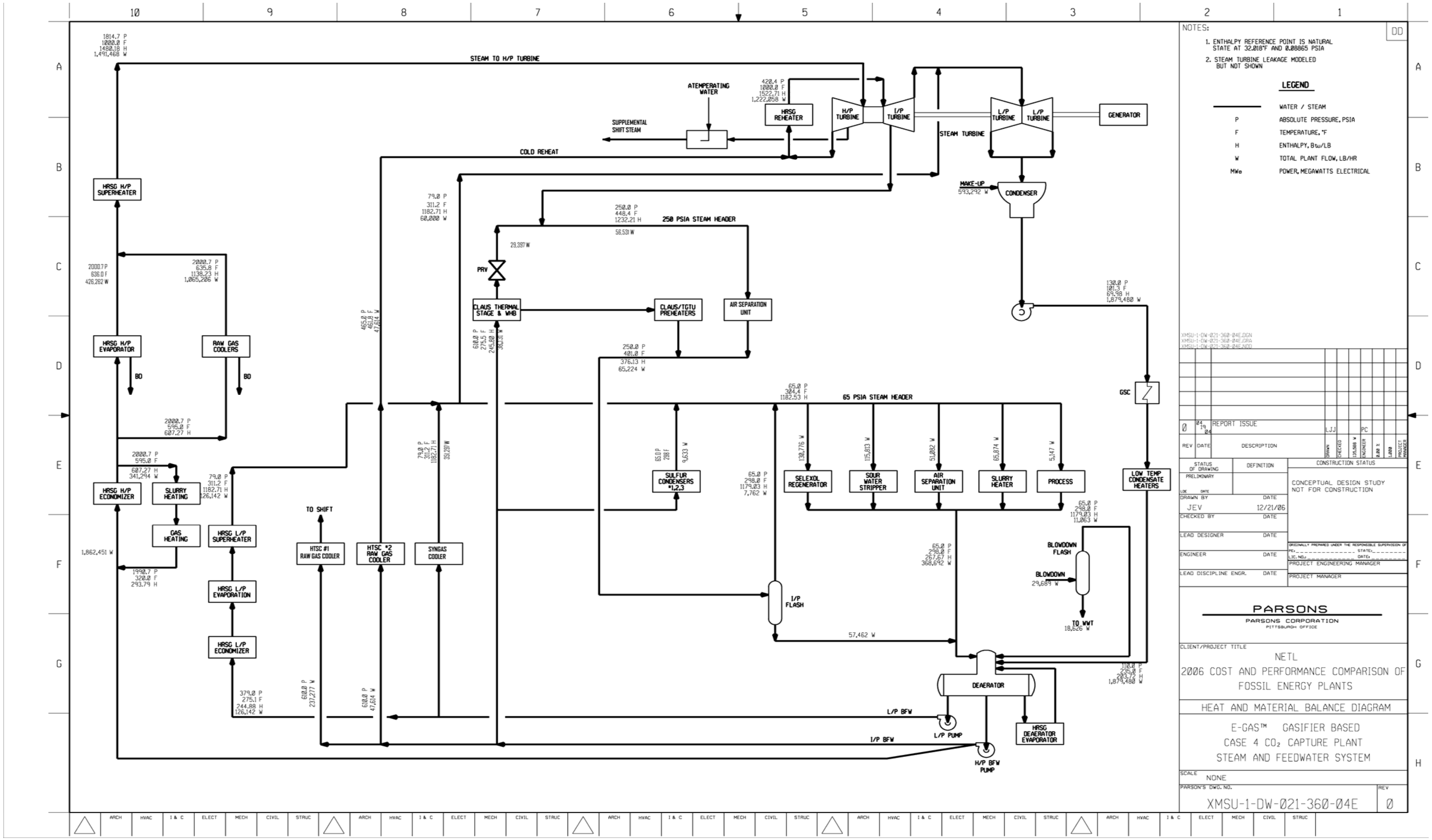

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Exhibit 3-77 Case 4 Overall Energy Balance (0°C [32°F] Reference)

	HHV	Sensible + Latent	Power	Total
Heat In (MMBtu/hr)				
Coal	5,575.1	4.7		5,579.8
ASU Air		21.1		21.1
CT Air		96.3		96.3
Water		16.9		16.9
Auxiliary Power			599.2	599.2
Totals	**5,575.1**	**138.9**	**599.2**	**6,313.2**
Heat Out (MMBtu/hr)				
ASU Intercoolers		240.9		240.9
ASU Vent		1.4		1.4
Slag	32.2	22.2		54.4
Sulfur	47.6	(1.1)		46.4
Tail Gas Compressor Intercoolers		3.9		3.9
CO_2 Compressor Intercoolers		130.7		130.7
CO_2 Product		(45.1)		(45.1)
HRSG Flue Gas		1,335.7		1,335.7
Condenser		1,161.0		1,161.0
Process Losses		980.4		980.4
Power			2,403.5	2,403.5
Totals	**79.8**	**3,830.0**	**2,403.5**	**6,313.2**

(1) Process Losses are calculated by difference and reflect various gasification, turbine, HRSG and other heat and work losses. Aspen flowsheet balance is within 0.5 percent.

3.3.10 CASE 4 - MAJOR EQUIPMENT LIST

Major equipment items for the CoP gasifier with CO_2 capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 3.3.11. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

ACCOUNT 1 COAL HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	181 tonne (200 ton)	2	0
2	Feeder	Belt	572 tonne/h (630 tph)	2	0
3	Conveyor No. 1	Belt	1,134 tonne/h (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,134 tonne/h (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,134 tonne/h (1,250 tph)	1	0
8	Reclaim Hopper	N/A	45 tonne (50 ton)	2	1
9	Feeder	Vibratory	181 tonne/h (200 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	354 tonne/h (390 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	181 tonne (200 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3" x 0 - 1-1/4" x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	354 tonne/h (390 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	354 tonne/h (390 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	816 tonne (900 ton)	3	0

ACCOUNT 2 COAL PREPARATION AND FEED

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Feeder	Vibratory	82 tonne/h (90 tph)	3	0
2	Conveyor No. 6	Belt w/tripper	236 tonne/h (260 tph)	1	0
3	Rod Mill Feed Hopper	Dual Outlet	481 tonne (530 ton)	1	0
4	Weigh Feeder	Belt	118 tonne/h (130 tph)	2	0
5	Rod Mill	Rotary	118 tonne/h (130 tph)	2	0
6	Slurry Water Storage Tank with Agitator	Field erected	295,264 liters (78,000 gal)	2	0
7	Slurry Water Pumps	Centrifugal	833 lpm (220 gpm)	2	2
10	Trommel Screen	Coarse	172 tonne/h (190 tph)	2	0
11	Rod Mill Discharge Tank with Agitator	Field erected	312,678 liters (82,600 gal)	2	0
12	Rod Mill Product Pumps	Centrifugal	2,612 lpm (690 gpm)	2	2
13	Slurry Storage Tank with Agitator	Field erected	946,361 liters (250,000 gal)	2	0
14	Slurry Recycle Pumps	Centrifugal	5,224 lpm (1,380 gpm)	2	2
15	Slurry Product Pumps	Positive displacement	2,612 lpm (690 gpm)	2	2

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	2,237,196 liters (591,000 gal)	3	0
2	Condensate Pumps	Vertical canned	7,874 lpm @ 91 m H2O (2,080 gpm @ 300 ft H2O)	2	1
3	Deaerator (integral w/ HRSG)	Horizontal spray type	577,877 kg/h (1,274,000 lb/h)	2	0
4	Intermediate Pressure Feedwater Pump	Horizontal centrifugal, single stage	2,006 lpm @ 283 m H2O (530 gpm @ 930 ft H2O)	2	1
5	High Pressure Feedwater Pump No. 1	Barrel type, multi-stage, centrifugal	HP water: 6,587 lpm @ 1,890 m H2O (1,740 gpm @ 6,200 ft H2O)	2	1
6	High Pressure Feedwater Pump No. 2	Barrel type, multi-stage, centrifugal	IP water: 1,476 lpm @ 223 m H2O (390 gpm @ 730 ft H2O)	2	1
7	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/h, 2.8 MPa, 343°C (40,000 lb/h, 400 psig, 650°F)	1	0
8	Service Air Compressors	Flooded Screw	28 m3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
9	Instrument Air Dryers	Duplex, regenerative	28 m3/min (1,000 scfm)	2	1
10	Closed Cylce Cooling Heat Exchangers	Plate and frame	58 MMkJ/h (55 MMBtu/h) each	2	0
11	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,820 lpm @ 21 m H2O (5,500 gpm @ 70 ft H2O)	2	1
12	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 107 m H2O (1,000 gpm @ 350 ft H2O)	1	1
13	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 76 m H2O (700 gpm @ 250 ft H2O)	1	1
14	Raw Water Pumps	Stainless steel, single suction	8,707 lpm @ 18 m H2O (2,300 gpm @ 60 ft H2O)	2	1
15	Filtered Water Pumps	Stainless steel, single suction	4,088 lpm @ 49 m H2O (1,080 gpm @ 160 ft H2O)	2	1
16	Filtered Water Tank	Vertical, cylindrical	1,968,429 liter (520,000 gal)	2	0
17	Makeup Water Demineralizer	Anion, cation, and mixed bed	2,574 lpm (680 gpm)	2	0
18	Liquid Waste Treatment System		10 years, 24-hour storm	1	0

ACCOUNT 4 GASIFIER, ASU AND ACCESSORIES INCLUDING LOW TEMPERATURE HEAT RECOVERY AND FUEL GAS SATURATION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gasifier	Pressurized two-stage, slurry-feed entrained bed	2,903 tonne/day, 4.2 MPa (3,200 tpd, 615 psia)	2	0
2	Synthesis Gas Cooler	Fire-tube boiler	326,133 kg/h (719,000 lb/h)	2	0
3	Synthesis Gas Cyclone	High efficiency	313,433 kg/h (691,000 lb/h) Design efficiency 90%	2	0
4	Candle Filter	Pressurized filter with pulse-jet cleaning	metallic filters	2	0
5	Syngas Scrubber Including Sour Water Stripper	Vertical upflow	299,825 kg/h (661,000 lb/h)	2	0
6	Raw Gas Coolers	Shell and tube with condensate drain	455,861 kg/h (1,005,000 lb/h)	8	0
7	Raw Gas Knockout Drum	Vertical with mist eliminator	351,988 kg/h, 38°C, 5.1 MPa (776,000 lb/h, 100°F, 737 psia)	2	0
8	Saturation Water Economizers	Shell and tube	455,861 kg/h (1,005,000 lb/h)	2	0
9	Fuel Gas Saturator	Vertical tray tower	62,596 kg/h, 149°C, 3.2 MPa (138,000 lb/h, 300°F, 458 psia)	2	0
10	Saturator Water Pump	Centrifugal	3,785 lpm @ 15 m H2O (1,000 gpm @ 50 ft H2O)	2	2
11	Synthesis Gas Reheater	Shell and tube	65,771 kg/h (145,000 lb/h)	2	0
12	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	299,825 kg/h (661,000 lb/h) syngas	2	0
13	ASU Main Air Compressor	Centrifugal, multi-stage	5,493 m3/min @ 1.3 MPa (194,000 scfm @ 190 psia)	2	0
14	Cold Box	Vendor design	2,177 tonne/day (2,400 tpd) of 95% purity oxygen	2	0
15	Oxygen Compressor	Centrifugal, multi-stage	1,104 m3/min @ 5.1 MPa (39,000 scfm @ 740 psia)	2	0
16	Nitrogen Compressor	Centrifugal, multi-stage	3,653 m3/min @ 3.4 MPa (129,000 scfm @ 490 psia)	2	0
17	Nitrogen Boost Compressor	Centrifugal, multi-stage	510 m3/min @ 2.3 MPa (18,000 scfm @ 340 psia)	2	0

ACCOUNT 5A SOUR GAS SHIFT AND SYNGAS CLEANUP

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Mercury Adsorber	Sulfated carbon bed	320,690 kg/h (707,000 lb/h) 34°C (93°F) 3.3 MPa (481 psia)	2	0
2	Sulfur Plant	Claus type	143 tonne/day (158 tpd)	1	0
3	Water Gas Shift Reactors	Fixed bed, catalytic	455,861 kg/h (1,005,000 lb/h) 232°C (450°F) 3.9 MPa (562 psia)	6	0
4	Shift Reactor Heat Recovery Exhchangers	Shell and Tube	Exchanger 1: 148 MMkJ/h (140 MMBtu/h) Exchanger 2: 32 MMkJ/h (30 MMBtu/h)	4	0
5	Acid Gas Removal Plant	Two-stage Selexol	292,567 kg/h (645,000 lb/h) 35°C (95°F) 3.2 MPa (471 psia)	2	0
6	Hydrogenation Reactor	Fixed bed, catalytic	17,100 kg/h (37,700 lb/h) 232°C (450°F) 0.2 MPa (25 psia)	1	0
7	Tail Gas Recycle Compressor	Centrifugal	11,975 kg/h @ 6.4 MPa (26,400 lb/h @ 930 psia)	1	0

ACCOUNT 5B CO_2 COMPRESSION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CO2 Compressor	Integrally geared, multi-stage centrifugal	1,096 m3/min @ 15.3 MPa (38,715 scfm @ 2,215 psia)	4	1

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gas Turbine	Advanced F class	232 MW	2	0
2	Gas Turbine Generator	TEWAC	260 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	2	0

ACCOUNT 7 HRSG, DUCTING, AND STACK

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	CS plate, type 409SS liner	76 m (250 ft) high x 8.5 m (28 ft) diameter	1	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	Main steam - 372,086 kg/h, 12.4 MPa/538°C (820,307 lb/h, 1,800 psig/1,000°F) Reheat steam - 304,874 kg/h, 2.9 MPa/538°C (672,132 lb/h, 420 psig/1,000°F)	2	0

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	251 MW 12.4 MPa/538°C/538°C (1800 psig/ 1000°F/1000°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitiation	280 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Steam Bypass	One per HRSG	50% steam flow @ design steam conditions	2	0
4	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,392 MMkJ/h (1,320 MMBtu/h), Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1	0

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	302,835 lpm @ 30 m (80,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT, 1,687 MMkJ/h (1,600 MMBtu/h) heat duty	1	0

ACCOUNT 10 SLAG RECOVERY AND HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Slag Quench Tank	Water bath	230,912 liters (61,000 gal)	2	0
2	Slag Crusher	Roll	12 tonne/h (13 tph)	2	0
3	Slag Depressurizer	Proprietary	12 tonne/h (13 tph)	2	0
4	Slag Receiving Tank	Horizontal, weir	151,418 liters (40,000 gal)	2	0
5	Black Water Overflow Tank	Shop fabricated	71,923 liters (19,000 gal)	2	
6	Slag Conveyor	Drag chain	12 tonne/h (13 tph)	2	0
7	Slag Separation Screen	Vibrating	12 tonne/h (13 tph)	2	0
8	Coarse Slag Conveyor	Belt/bucket	12 tonne/h (13 tph)	2	0
9	Fine Ash Settling Tank	Vertical, gravity	227,126 liters (60,000 gal)	2	0
10	Fine Ash Recycle Pumps	Horizontal centrifugal	38 lpm @ 14 m H2O (10 gpm @ 46 ft H2O)	2	2
11	Grey Water Storage Tank	Field erected	71,923 liters (19,000 gal)	2	0
12	Grey Water Pumps	Centrifugal	265 lpm @ 433 m H2O (70 gpm @ 1,420 ft H2O)	2	2
13	Grey Water Recycle Heat Exchanger	Shell and tube	15,876 kg/h (35,000 lb/h)	2	0
14	Slag Storage Bin	Vertical, field erected	907 tonne (1,000 tons)	2	0
15	Unloading Equipment	Telescoping chute	100 tonne/h (110 tph)	1	0

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	24 kV/345 kV, 260 MVA, 3-ph, 60 Hz	2	0
2	STG Transformer	Oil-filled	24 kV/345 kV, 80 MVA, 3-ph, 60 Hz	1	0
3	Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 191 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 29 MVA, 3-ph, 60 Hz	1	1
5	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	2	0
6	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
7	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
8	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
9	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

ACCOUNT 12 INSTRUMENTATION AND CONTROLS

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

3.3.11 CASE 4 - COST ESTIMATING RESULTS

The cost estimating methodology was described previously in Section 2.6. Exhibit 3-78 shows the total plant capital cost summary organized by cost account and Exhibit 3-79 shows a more detailed breakdown of the capital costs. Exhibit 3-80 shows the initial and annual O&M costs.

The estimated TPC of the CoP gasifier with CO_2 capture is $2,431/kW. Process contingency represents 4.3 percent of the TPC and project contingency represents 13.7 percent. The 20-year LCOE, including CO_2 TS&M costs of 4.1 mills/kWh, is 105.7 mills/kWh.

Exhibit 3-78 Case 4 Total Plant Cost Summary

Client:	USDOE/NETL
Project:	Bituminous Baseline Study
Report Date:	05-Apr-07
Case:	Case 04 - ConocoPhillips IGCC w/ CO2
Plant Size:	518.2 MW,net
Estimate Type:	Conceptual
Cost Base (Dec)	2006 ($x1000)

TOTAL PLANT COST SUMMARY

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	$13,303	$2,480	$10,424	$0	$0	**$26,207**	$2,127	$0	$5,667	**$34,000**	$66
2	COAL & SORBENT PREP & FEED	$22,651	$4,146	$13,827	$0	$0	**$40,624**	$3,263	$0	$8,777	**$52,665**	$102
3	FEEDWATER & MISC. BOP SYSTEMS	$9,371	$7,975	$8,947	$0	$0	**$26,292**	$2,201	$0	$6,451	**$34,944**	$67
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries	$93,113	$0	$57,142	$0	$0	**$150,256**	$12,324	$22,538	$27,768	**$212,885**	$411
4.2	Syngas Cooling (w/ 4.1)	w/4.1	$0	w/4.1	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.3	ASU/Oxidant Compression	$142,779	$0	w/equip.	$0	$0	**$142,779**	$12,175	$0	$15,495	**$170,449**	$329
4.4-4.9	Other Gasification Equipment	$24,864	$8,707	$14,165	$0	$0	**$47,736**	$4,057	$0	$11,002	**$62,795**	$121
	SUBTOTAL 4	**$260,756**	**$8,707**	**$71,307**	**$0**	**$0**	**$340,771**	**$28,555**	**$22,538**	**$54,265**	**$446,129**	**$861**
5A	Gas Cleanup & Piping	$81,314	$4,446	$69,562	$0	$0	**$155,321**	$13,338	$21,481	$38,231	**$228,370**	$441
5B	CO_2 REMOVAL & COMPRESSION	$17,010	$0	$10,435	$0	$0	**$27,445**	$2,351	$0	$5,959	**$35,754**	$69
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$88,000	$0	$5,325	$0	$0	**$93,325**	$7,865	$9,333	$11,052	**$121,575**	$235
6.2-6.9	Combustion Turbine Other	$0	$684	$762	$0	$0	**$1,446**	$121	$0	$470	**$2,037**	$4
	SUBTOTAL 6	**$88,000**	**$684**	**$6,087**	**$0**	**$0**	**$94,771**	**$7,986**	**$9,333**	**$11,522**	**$123,611**	**$239**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$32,356	$0	$4,604	$0	$0	**$36,960**	$3,125	$0	$4,009	**$44,094**	$85
7.2-7.9	Ductwork and Stack	$3,222	$2,268	$3,011	$0	$0	**$8,501**	$703	$0	$1,496	**$10,700**	$21
	SUBTOTAL 7	**$35,577**	**$2,268**	**$7,615**	**$0**	**$0**	**$45,461**	**$3,829**	**$0**	**$5,505**	**$54,794**	**$106**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$25,224	$0	$4,105	$0	$0	**$29,328**	$2,518	$0	$3,185	**$35,030**	$68
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$9,243	$828	$6,527	$0	$0	**$16,598**	$1,338	$0	$3,645	**$21,581**	$42
	SUBTOTAL 8	**$34,466**	**$828**	**$10,632**	**$0**	**$0**	**$45,926**	**$3,856**	**$0**	**$6,829**	**$56,611**	**$109**
9	COOLING WATER SYSTEM	$6,318	$6,821	$5,729	$0	$0	**$18,867**	$1,553	$0	$4,194	**$24,614**	$47
10	ASH/SPENT SORBENT HANDLING SYS	$18,516	$1,396	$9,191	$0	$0	**$29,103**	$2,482	$0	$3,445	**$35,031**	$68
11	ACCESSORY ELECTRIC PLANT	$23,064	$11,396	$22,575	$0	$0	**$57,035**	$4,450	$0	$11,923	**$73,409**	$142
12	INSTRUMENTATION & CONTROL	$10,183	$1,906	$6,836	$0	$0	**$18,925**	$1,562	$946	$3,586	**$25,021**	$48
13	IMPROVEMENTS TO SITE	$3,208	$1,891	$7,974	$0	$0	**$13,073**	$1,151	$0	$4,267	**$18,490**	$36
14	BUILDINGS & STRUCTURES	$0	$6,066	$6,992	$0	$0	**$13,057**	$1,063	$0	$2,319	**$16,439**	$32
	TOTAL COST	**$623,738**	**$61,009**	**$268,131**	**$0**	**$0**	**$952,878**	**$79,766**	**$54,298**	**$172,940**	**$1,259,883**	**$2,431**

Exhibit 3-79 Case 4 Total Plant Cost Details

Client: USDOE/NETL **Report Date:** 05-Apr-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 04 - ConocoPhillips IGCC w/ CO2
Plant Size: 518.2 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	$3,493	$0	$1,725	$0	$0	$5,218	$418	$0	$1,127	$6,764	$13
1.2	Coal Stackout & Reclaim	$4,514	$0	$1,106	$0	$0	$5,620	$441	$0	$1,212	$7,274	$14
1.3	Coal Conveyors	$4,197	$0	$1,094	$0	$0	$5,291	$416	$0	$1,141	$6,849	$13
1.4	Other Coal Handling	$1,098	$0	$253	$0	$0	$1,351	$106	$0	$291	$1,749	$3
1.5	Sorbent Receive & Unload	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.6	Sorbent Stackout & Reclaim	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.7	Sorbent Conveyors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.8	Other Sorbent Handling	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.9	Coal & Sorbent Hnd.Foundations	$0	$2,480	$6,246	$0	$0	$8,726	$745	$0	$1,894	$11,365	$22
	SUBTOTAL 1.	**$13,303**	**$2,480**	**$10,424**	**$0**	**$0**	**$26,207**	**$2,127**	**$0**	**$5,667**	**$34,000**	**$66**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying incl w/2.3	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.2	Prepared Coal Storage & Feed	$1,491	$355	$236	$0	$0	$2,082	$160	$0	$448	$2,690	$5
2.3	Slurry Prep & Feed	$20,340	$0	$9,140	$0	$0	$29,480	$2,356	$0	$6,367	$38,204	$74
2.4	Misc.Coal Prep & Feed	$820	$593	$1,807	$0	$0	$3,221	$265	$0	$697	$4,182	$8
2.5	Sorbent Prep Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.6	Sorbent Storage & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.7	Sorbent Injection System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.8	Booster Air Supply System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.9	Coal & Sorbent Feed Foundation	$0	$3,197	$2,644	$0	$0	$5,841	$483	$0	$1,265	$7,588	$15
	SUBTOTAL 2.	**$22,651**	**$4,146**	**$13,827**	**$0**	**$0**	**$40,624**	**$3,263**	**$0**	**$8,777**	**$52,665**	**$102**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	$3,088	$5,369	$2,836	$0	$0	$11,293	$934	$0	$2,445	$14,672	$28
3.2	Water Makeup & Pretreating	$537	$56	$300	$0	$0	$893	$76	$0	$290	$1,259	$2
3.3	Other Feedwater Subsystems	$1,705	$578	$521	$0	$0	$2,804	$225	$0	$606	$3,634	$7
3.4	Service Water Systems	$309	$632	$2,194	$0	$0	$3,135	$272	$0	$1,022	$4,428	$9
3.5	Other Boiler Plant Systems	$1,662	$638	$1,582	$0	$0	$3,882	$326	$0	$842	$5,050	$10
3.6	FO Supply Sys & Nat Gas	$299	$565	$527	$0	$0	$1,391	$119	$0	$302	$1,812	$3
3.7	Waste Treatment Equipment	$746	$0	$457	$0	$0	$1,203	$104	$0	$392	$1,700	$3
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	$1,024	$138	$531	$0	$0	$1,693	$146	$0	$552	$2,390	$5
	SUBTOTAL 3.	**$9,371**	**$7,975**	**$8,947**	**$0**	**$0**	**$26,292**	**$2,201**	**$0**	**$6,451**	**$34,944**	**$67**
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries (E-GAS)	$93,113	$0	$57,142	$0	$0	$150,256	$12,324	$22,538	$27,768	$212,885	$411
4.2	Syngas Cooling (w/ 4.1	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.3	ASU/Oxidant Compression	$142,779	$0	w/equip.	$0	$0	$142,779	$12,175	$0	$15,495	$170,449	$329
4.4	LT Heat Recovery & FG Saturation	$24,864	$0	$9,355	$0	$0	$34,219	$2,946	$0	$7,433	$44,598	$86
4.5	Misc. Gasification Equipment w/4.1 & 4.2	w/4.1&4.2	$0	w/4.1&4.2	$0	$0	$0	$0	$0	$0	$0	$0
4.6	Other Gasification Equipment	$0	$1,157	$471	$0	$0	$1,629	$139	$0	$354	$2,121	$4
4.8	Major Component Rigging	w/4.1&4.2	$0	w/4.1&4.2	$0	$0	$0	$0	$0	$0	$0	$0
4.9	Gasification Foundations	$0	$7,550	$4,339	$0	$0	$11,889	$972	$0	$3,215	$16,075	$31
	SUBTOTAL 4.	**$260,756**	**$8,707**	**$71,307**	**$0**	**$0**	**$340,771**	**$28,555**	**$22,538**	**$54,265**	**$446,129**	**$861**

Exhibit 3-79 Case 4 Total Plant Cost Details (Continued)

Client: USDOE/NETL **Report Date:** 05-Apr-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 04 - ConocoPhillips IGCC w/ CO2
Plant Size: 518.2 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct		Equipment	Material	Labor		Sales	Bare Erected	Eng'g CM	Contingencies		TOTAL PLANT COST	
No.	Item/Description	Cost	Cost	Direct	Indirect	Tax	Cost $	H.O.& Fee	Process	Project	$	$/kW
5A	GAS CLEANUP & PIPING											
5A.1	Double Stage Selexol	$57,451	$0	$49,279	$0	$0	$106,730	$9,179	$21,346	$27,451	$164,707	$318
5A.2	Elemental Sulfur Plant	$9,709	$1,927	$12,535	$0	$0	$24,170	$2,088	$0	$5,252	$31,510	$61
5A.3	Mercury Removal	$1,531	$0	$1,166	$0	$0	$2,697	$232	$135	$613	$3,676	$7
5A.4	Shift Reactors	$12,213	$0	$4,919	$0	$0	$17,133	$1,461	$0	$3,719	$22,312	$43
5A.5	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.6	Blowback Gas Systems	$410	$230	$130	$0	$0	$770	$65	$0	$167	$1,002	$2
5A.7	Fuel Gas Piping	$0	$1,150	$793	$0	$0	$1,943	$159	$0	$420	$2,522	$5
5A.9	HGCU Foundations	$0	$1,138	$739	$0	$0	$1,878	$154	$0	$609	$2,641	$5
	SUBTOTAL 5A.	**$81,314**	**$4,446**	**$69,562**	**$0**	**$0**	**$155,321**	**$13,338**	**$21,481**	**$38,231**	**$228,370**	**$441**
5B	CO2 REMOVAL & COMPRESSION											
5B.1	CO2 Removal System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5B.2	CO2 Compression & Drying	$17,010	$0	$10,435	$0	$0	$27,445	$2,351	$0	$5,959	$35,754	$69
	SUBTOTAL 5B.	**$17,010**	**$0**	**$10,435**	**$0**	**$0**	**$27,445**	**$2,351**	**$0**	**$5,959**	**$35,754**	**$69**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$88,000	$0	$5,325	$0	$0	$93,325	$7,865	$9,333	$11,052	$121,575	$235
6.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.3	Compressed Air Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.9	Combustion Turbine Foundations	$0	$684	$762	$0	$0	$1,446	$121	$0	$470	$2,037	$4
	SUBTOTAL 6.	**$88,000**	**$684**	**$6,087**	**$0**	**$0**	**$94,771**	**$7,986**	**$9,333**	**$11,522**	**$123,611**	**$239**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$32,356	$0	$4,604	$0	$0	$36,960	$3,125	$0	$4,009	$44,094	$85
7.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$0	$1,627	$1,179	$0	$0	$2,806	$221	$0	$605	$3,632	$7
7.4	Stack	$3,222	$0	$1,211	$0	$0	$4,433	$378	$0	$481	$5,292	$10
7.9	HRSG,Duct & Stack Foundations	$0	$641	$620	$0	$0	$1,262	$105	$0	$410	$1,777	$3
	SUBTOTAL 7.	**$35,577**	**$2,268**	**$7,615**	**$0**	**$0**	**$45,461**	**$3,829**	**$0**	**$5,505**	**$54,794**	**$106**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$25,224	$0	$4,105	$0	$0	$29,328	$2,518	$0	$3,185	$35,030	$68
8.2	Turbine Plant Auxiliaries	$168	$0	$385	$0	$0	$553	$48	$0	$60	$662	$1
8.3	Condenser & Auxiliaries	$4,112	$0	$1,235	$0	$0	$5,348	$455	$0	$580	$6,382	$12
8.4	Steam Piping	$4,962	$0	$3,497	$0	$0	$8,459	$647	$0	$2,276	$11,382	$22
8.9	TG Foundations	$0	$828	$1,409	$0	$0	$2,237	$189	$0	$728	$3,154	$6
	SUBTOTAL 8.	**$34,466**	**$828**	**$10,632**	**$0**	**$0**	**$45,926**	**$3,856**	**$0**	**$6,829**	**$56,611**	**$109**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$4,081	$0	$897	$0	$0	$4,978	$422	$0	$810	$6,210	$12
9.2	Circulating Water Pumps	$1,284	$0	$77	$0	$0	$1,361	$104	$0	$220	$1,685	$3
9.3	Circ.Water System Auxiliaries	$108	$0	$15	$0	$0	$123	$10	$0	$20	$154	$0
9.4	Circ.Water Piping	$0	$4,606	$1,175	$0	$0	$5,781	$459	$0	$1,248	$7,488	$14
9.5	Make-up Water System	$301	$0	$427	$0	$0	$729	$62	$0	$158	$949	$2
9.6	Component Cooling Water Sys	$544	$650	$459	$0	$0	$1,653	$137	$0	$358	$2,148	$4
9.9	Circ.Water System Foundations& Structures	$0	$1,564	$2,678	$0	$0	$4,242	$358	$0	$1,380	$5,981	$12
	SUBTOTAL 9.	**$6,318**	**$6,821**	**$5,729**	**$0**	**$0**	**$18,867**	**$1,553**	**$0**	**$4,194**	**$24,614**	**$47**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Slag Dewatering & Cooling	$16,165	$0	$7,978	$0	$0	$24,143	$2,063	$0	$2,621	$28,826	$56
10.2	Gasifier Ash Depressurization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.3	Cleanup Ash Depressurization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.4	High Temperature Ash Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.5	Other Ash Rrecovery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$532	$0	$579	$0	$0	$1,111	$96	$0	$181	$1,387	$3
10.7	Ash Transport & Feed Equipment	$718	$0	$172	$0	$0	$890	$73	$0	$145	$1,108	$2
10.8	Misc. Ash Handling Equipment	$1,101	$1,350	$403	$0	$0	$2,854	$242	$0	$464	$3,560	$7
10.9	Ash/Spent Sorbent Foundation	$0	$47	$59	$0	$0	$106	$9	$0	$34	$149	$0
	SUBTOTAL 10.	**$18,516**	**$1,396**	**$9,191**	**$0**	**$0**	**$29,103**	**$2,482**	**$0**	**$3,445**	**$35,031**	**$68**

Exhibit 3-79 Case 4 Total Plant Cost Details (Continued)

Client: USDOE/NETL **Report Date:** 05-Apr-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 04 - ConocoPhillips IGCC w/ CO2
Plant Size: 518.2 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$866	$0	$864	$0	$0	$1,730	$147	$0	$188	$2,065	$4
11.2	Station Service Equipment	$4,122	$0	$387	$0	$0	$4,509	$384	$0	$489	$5,381	$10
11.3	Switchgear & Motor Control	$7,876	$0	$1,444	$0	$0	$9,320	$773	$0	$1,514	$11,608	$22
11.4	Conduit & Cable Tray	$0	$3,748	$12,166	$0	$0	$15,914	$1,363	$0	$4,319	$21,596	$42
11.5	Wire & Cable	$0	$6,883	$4,630	$0	$0	$11,512	$754	$0	$3,067	$15,333	$30
11.6	Protective Equipment	$0	$624	$2,365	$0	$0	$2,989	$262	$0	$488	$3,739	$7
11.7	Standby Equipment	$208	$0	$211	$0	$0	$419	$36	$0	$68	$524	$1
11.8	Main Power Transformers	$9,992	$0	$132	$0	$0	$10,124	$687	$0	$1,622	$12,432	$24
11.9	Electrical Foundations	$0	$142	$376	$0	$0	$518	$44	$0	$169	$730	$1
	SUBTOTAL 11.	**$23,064**	**$11,396**	**$22,575**	**$0**	**$0**	**$57,035**	**$4,450**	**$0**	**$11,923**	**$73,409**	**$142**
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
12.3	Steam Turbine Control	w/8.1	$0	w/8.1	$0	$0	$0	$0	$0	$0	$0	$0
12.4	Other Major Component Control	$1,005	$0	$699	$0	$0	$1,705	$147	$85	$291	$2,227	$4
12.5	Signal Processing Equipment	W/12.7	$0	W/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.6	Control Boards,Panels & Racks	$231	$0	$154	$0	$0	$385	$33	$19	$88	$525	$1
12.7	Computer & Accessories	$5,362	$0	$179	$0	$0	$5,541	$470	$277	$629	$6,918	$13
12.8	Instrument Wiring & Tubing	$0	$1,906	$3,990	$0	$0	$5,896	$448	$295	$1,660	$8,299	$16
12.9	Other I & C Equipment	$3,584	$0	$1,813	$0	$0	$5,398	$464	$270	$920	$7,052	$14
	SUBTOTAL 12.	**$10,183**	**$1,906**	**$6,836**	**$0**	**$0**	**$18,925**	**$1,562**	**$946**	**$3,586**	**$25,021**	**$48**
13	Improvements to Site											
13.1	Site Preparation	$0	$101	$2,167	$0	$0	$2,268	$200	$0	$740	$3,209	$6
13.2	Site Improvements	$0	$1,790	$2,397	$0	$0	$4,187	$368	$0	$1,367	$5,922	$11
13.3	Site Facilities	$3,208	$0	$3,410	$0	$0	$6,618	$582	$0	$2,160	$9,360	$18
	SUBTOTAL 13.	**$3,208**	**$1,891**	**$7,974**	**$0**	**$0**	**$13,073**	**$1,151**	**$0**	**$4,267**	**$18,490**	**$36**
14	Buildings & Structures											
14.1	Combustion Turbine Area	$0	$221	$127	$0	$0	$348	$27	$0	$75	$451	$1
14.2	Steam Turbine Building	$0	$2,058	$2,971	$0	$0	$5,030	$414	$0	$816	$6,260	$12
14.3	Administration Building	$0	$814	$598	$0	$0	$1,412	$113	$0	$229	$1,753	$3
14.4	Circulation Water Pumphouse	$0	$153	$82	$0	$0	$235	$18	$0	$38	$291	$1
14.5	Water Treatment Buildings	$0	$427	$423	$0	$0	$850	$69	$0	$138	$1,057	$2
14.6	Machine Shop	$0	$417	$289	$0	$0	$705	$56	$0	$114	$876	$2
14.7	Warehouse	$0	$672	$440	$0	$0	$1,112	$88	$0	$180	$1,381	$3
14.8	Other Buildings & Structures	$0	$403	$318	$0	$0	$721	$58	$0	$156	$934	$2
14.9	Waste Treating Building & Str.	$0	$900	$1,744	$0	$0	$2,644	$220	$0	$573	$3,437	$7
	SUBTOTAL 14.	**$0**	**$6,066**	**$6,992**	**$0**	**$0**	**$13,057**	**$1,063**	**$0**	**$2,319**	**$16,439**	**$32**
	TOTAL COST	**$623,738**	**$61,009**	**$268,131**	**$0**	**$0**	**$952,878**	**$79,766**	**$54,298**	**$172,940**	**$1,259,883**	**$2,431**

Exhibit 3-80 Case 4 Initial and Annual Operating and Maintenance Costs

INITIAL & ANNUAL O&M EXPENSES					Cost Base (Dec)	2006
Case 04 - ConocoPhillips IGCC w/ CO2					Heat Rate-net(Btu/kWh):	10,757
					MWe-net:	518
					Capacity Factor: (%):	80
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate(base):	33.00 $/hour					
Operating Labor Burden:	30.00 % of base					
Labor O-H Charge Rate:	25.00 % of labor					
			Total			
Skilled Operator	2.0		2.0			
Operator	10.0		10.0			
Foreman	1.0		1.0			
Lab Tech's, etc.	3.0		3.0			
TOTAL-O.J.'s	16.0		16.0			
					Annual Cost $	Annual Unit Cost $/kW-net
Annual Operating Labor Cost					$6,012,864	$11.602
Maintenance Labor Cost					$13,171,520	$25.416
Administrative & Support Labor					$4,796,096	$9.255
TOTAL FIXED OPERATING COSTS					**$23,980,481**	**$46.273**
VARIABLE OPERATING COSTS						
						$/kWh-net
Maintenance Material Cost					**$24,211,567**	**$0.00667**
Consumables	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost		
Water(/1000 gallons)	0	5,954	1.03	**$0**	**$1,790,845**	**$0.00049**
Chemicals						
MU & WT Chem.(lb)	124,161	17,737	0.16	$20,462	$853,547	$0.00024
Carbon (Mercury Removal) (lb)	128,090	175	1.00	$128,090	$51,100	$0.00001
COS Catalyst (m3)	0	0	2,308.40	$0	$0	$0.00000
Water Gas Shift Catalyst(ft3)	11,053	7.57	475.00	$5,250,175	$1,049,363	$0.00029
Selexol Solution (gal.)	462	66	12.90	$5,960	$248,630	$0.00007
MDEA Solution (gal)	0	0	0.96	$0	$0	$0.00000
Sulfinol Solution (gal)	0	0	9.68	$0	$0	$0.00000
SCR Catalyst (m3)	0	0	0.00	$0	$0	$0.00000
Aqueous Ammonia (ton)	0	0	0.00	$0	$0	$0.00000
Claus Catalyst(ft3)	w/equip.	2.16	125.00	$0	$78,840	$0.00002
Subtotal Chemicals				**$5,404,687**	**$2,281,480**	**$0.00063**
Other						
Supplemental Fuel(MBtu)	0	0	0.00	$0	$0	$0.00000
Gases,N2 etc.(/100scf)	0	0	0.00	$0	$0	$0.00000
L.P. Steam(/1000 pounds)	0	0	0.00	$0	$0	$0.00000
Subtotal Other				**$0**	**$0**	$0.00000
Waste Disposal						
Spent Mercury Catalyst (lb)	0	175	0.40	$0	$20,522	$0.00001
Flyash (ton)	0	0	0.00	$0	$0	$0.00000
Bottom Ash(ton)	0	583	15.45	$0	$2,632,348	$0.00072
Subtotal-Waste Disposal				**$0**	**$2,652,870**	**$0.00073**
By-products & Emissions						
Sulfur(tons)	0	143	0.00	$0	$0	$0.00000
Subtotal By-Products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$5,404,687**	**$30,936,762**	**$0.00852**
Fuel(ton)	172,030	5,734	42.11	**$7,244,210**	**$70,510,306**	**$0.01941**

3.4 SHELL GLOBAL SOLUTIONS IGCC CASES

This section contains an evaluation of plant designs for Cases 5 and 6, which are based on the Shell Global Solutions (Shell) gasifier. Cases 5 and 6 are very similar in terms of process, equipment, scope and arrangement, except that Case 6 employs a syngas quench and includes sour gas shift reactors, CO_2 absorption/regeneration and compression/transport systems. There are no provisions for CO_2 removal in Case 5.

The balance of this section is organized in an analogous manner to Sections 3.2 and 3.3:

- Gasifier Background
- Process System Decscription for Case 5
- Key Assumptions for Cases 5 and 6
- Sparing Philosophy for Cases 5 and 6
- Performance Results for Case 5
- Equipment List for Case 5
- Cost Estimates For Case 5
- Process and System Description, Performance Results, Equipment List and Cost Estimate for Case 6

3.4.1 GASIFIER BACKGROUND

Development and Current Status – Development of the Shell gasification process for partial oxidation of oil and gas began in the early 1950s. More than 75 commercial Shell partial-oxidation plants have been built worldwide to convert a variety of hydrocarbon liquids and gases to carbon monoxide and hydrogen.

Shell Internationale Petroleum Maatschappij B.V. began work on coal gasification in 1972. The coal gasifier is significantly different than the oil and gas gasifiers developed earlier. A pressurized, entrained-flow, slagging coal gasifier was built at Shell's Amsterdam laboratories. This 5 tonnes/day (6 TPD) process development unit has operated for approximately 12,000 hours since 1976. A larger 150 tonnes/day (165 TPD) pilot plant was built at Shell's Hamburg refinery in Hamburg, Germany. This larger unit operated for approximately 6,000 hours from 1978 to 1983, and successfully gasified over 27,216 tonnes (30,000 tons) of coal.

From 1974 until mid-1981, Heinrich Koppers GmbH (now Krupp Koppers) cooperated with Shell in the development work for the coal gasification technology at the 150 tonnes/day (165 TPD) pilot plant in Hamburg. Krupp Koppers is the licensor of the commercially proven Koppers-Totzek coal gasification technology, an entrained-flow slagging gasification system operated at atmospheric pressure.

In June 1981, the partnership between Shell and Krupp Koppers was terminated. Since that time, this gasification technology has been developed solely by Shell as the Shell Coal Gasification Process. Krupp Koppers continued its own development of a similar pressurized, dry feed, entrained-flow gasification technology called PRENFLO. Krupp Koppers has built and successfully operated a small 45 tonnes/day (50 TPD) PRENFLO pilot plant at Fuerstenhausen, Germany. In 2000 Shell and Krupp Uhde agreed to join forces again in gasification and jointly offer the Shell coal gasification process.

Based on the experience it gained with the Hamburg unit, Shell built a demonstration unit at its oil refinery and chemical complex in Deer Park, Texas, near Houston. This new unit, commonly called SCGP-1 (for Shell Coal Gasification Plant-1), was designed to gasify bituminous coal at the rate of 227 tonnes/day (250 TPD) and to gasify high-moisture, high-ash lignite at the rate of 363 tonnes/day (400 TPD). The relatively small difference in size between the Hamburg and Deer Park units reflects design changes and improvements.

The Deer Park demonstration plant operated successfully after startup in July 1987. Before the end of the program in 1991, after 15,000 hours of operation, 18 different feedstocks were gasified at the plant, including domestic coals ranging from lignite to high-sulfur bituminous, three widely traded foreign coals, and petroleum coke. The Deer Park unit produced superheated high-pressure steam in the waste heat recovery boiler. The plant also had facilities for extensive environmental monitoring and for sidestream testing of several AGR processes, including Sulfinol-D, Sulfinol-M, highly loaded MDEA, and various wastewater treatment schemes.

In spring 1989, Shell announced that its technology had been selected for the large commercial-scale Demkolec B.V. IGCC plant at Buggenum, near Roermond, in The Netherlands. This plant generates 250 MW of IGCC electricity with a single Shell gasifier consuming 1,814 tonnes/day (2,000 TPD) (dry basis) of coal. The plant was originally owned and operated by Samenwerkende Electriciteits-Productiebedrijven NV (SEP), a consortium of Dutch utilities, and began operation in 1994. In 2000 the plant was purchased by Nuon. Shell was extensively involved in the design, startup, and initial operation of this plant. A key feature of this design is the use of extraction air from the combustion turbine air compressor to feed the oxygen plant.

Gasifier Capacity – The large gasifier operating in The Netherlands has a bituminous coal-handling capacity of 1,633 tonnes/day (1,800 TPD) and produces dry gas at a rate of 158,575 Nm^3/h (5.6 million scf/h) with an energy content of about 1,792 MMkJ/h (1,700 MMBtu/h) (HHV). This gasifier was sized to match the fuel gas requirements for the Siemens/Kraftwerk Union V-94.2 combustion turbine and could easily be scaled up to match advanced F Class turbine requirements.

Distinguishing Characteristics – The key advantage of the Shell coal gasification technology is its lack of feed coal limitations. One of the major achievements of the Shell development program has been the successful gasification of a wide variety of coals ranging from anthracite to brown coal. The dry pulverized feed system developed by Shell uses all coal types with essentially no operating and design modifications (provided the drying pulverizers are appropriately sized). The dry fed Shell gasifier also has the advantage of lower oxygen requirement than comparable slurry fed entrained flow gasifiers.

Entrained-flow slagging gasifiers have fundamental environmental advantages over fluidized-bed and moving-bed gasifiers. They produce no hydrocarbon liquids, and the only solid waste is an inert slag. The dry feed entrained-flow gasifiers also have minor environmental advantages over the slurry feed entrained-flow gasifiers. They produce a higher H_2S/CO_2 ratio acid gas, which improves sulfur recovery and lessens some of the gray water processing and the fixed-salts blowdown problems associated with slurry feeding.

A disadvantage of the Shell coal gasification technology is the high waste heat recovery (synthesis gas cooler) duty. As with the other slagging gasifiers, the Shell process has this disadvantage due to its high operating temperature. The ability to feed dry solids minimizes the oxygen requirement and makes the Shell gasifier somewhat more efficient than entrained flow gasifiers employing slurry feed systems. The penalty paid for this increase in efficiency is a coal feed system that is more costly and operationally more complex. Demonstration of the reliability and safety of the dry coal feeding system was essential for the successful development of the Shell technology. The high operating temperature required by all entrained-flow slagging processes can result in relatively high capital and maintenance costs. However, the Shell gasifier employs a cooled refractory, which requires fewer changeouts than an uncooled refractory. Life of a water wall is determined by metallurgy and temperature and can provide a significant O&M cost benefit over refractory lined gasifiers.

Important Coal Characteristics – Characteristics desirable for coal considered for use in the Shell gasifier include moderate ash fusion temperature and relatively low ash content. The Shell gasifier is extremely flexible; it can handle a wide variety of different coals, including lignite. High-ash fusion-temperature coals may require flux addition for optimal gasifier operation. The ash content, fusion temperature, and composition affect the required gasifier operating temperature level, oxygen requirements, heat removal, slag management, and maintenance. However, dry feeding reduces the negative effects of high ash content relative to slurry feed gasifiers.

3.4.2 PROCESS DESCRIPTION

In this section the overall Shell gasification process for Case 5 is described. The system description follows the BFD in Exhibit 3-81 and stream numbers reference the same Exhibit. The tables in Exhibit 3-82 provide process data for the numbered streams in the BFD.

Coal Preparation and Feed Systems

Coal receiving and handling is common to all cases and was covered in Section 3.1.1. The receiving and handling subsystem ends at the coal silo. The Shell process uses a dry feed system which is sensitive to the coal moisture content. Coal moisture consists of two parts, surface moisture and inherent moisture. For coal to flow smoothly through the lock hoppers, the surface moisture must be removed. The Illinois No. 6 coal used in this study contains 11.12 percent total moisture on an as-received basis (stream 9). It was assumed that the coal must be dried to 5 percent moisture to allow for smooth flow through the dry feed system (stream 10).

The coal is simultaneously crushed and dried in the coal mill then delivered to a surge hopper with an approximate 2-hour capacity. The drying medium is provided by combining the off-gas from the Claus plant TGTU and a slipstream of clean syngas (stream 8) and passing them through an incinerator. The incinerator flue gas, with an oxygen content of 6 vol%, is then used to dry the coal in the mill.

The coal is drawn from the surge hoppers and fed through a pressurization lock hopper system to a dense phase pneumatic conveyor, which uses nitrogen from the ASU to convey the coal to the gasifiers.

Exhibit 3-81 Case 5 Process Flow Diagram, Shell IGCC without CO_2 Capture

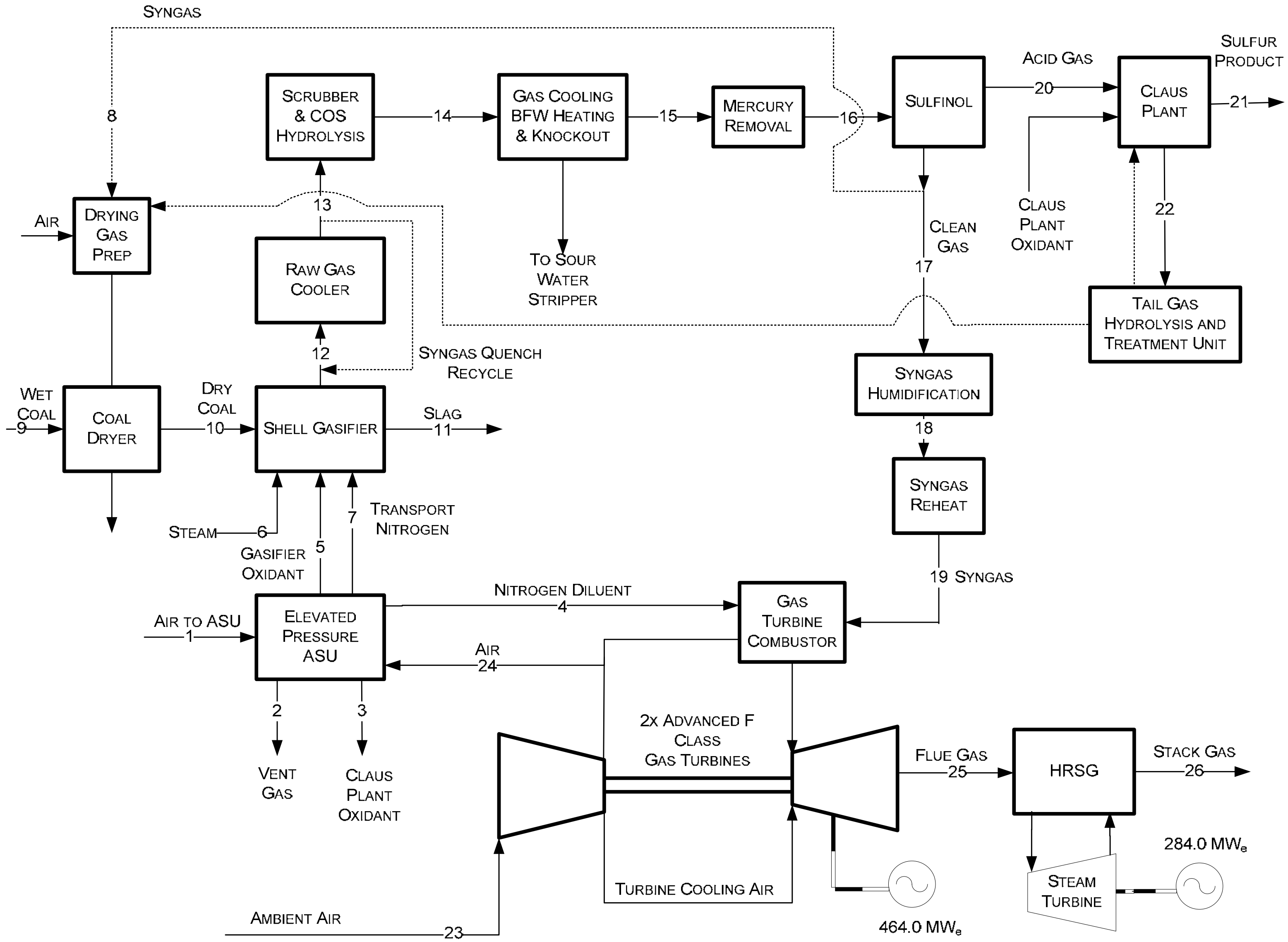

Exhibit 3-82 Case 5 Stream Table, Shell IGCC without CO_2 Capture

	1	2	3	4	5	6	7	8	9[A]	10[A]	11	12	13
V-L Mole Fraction													
Ar	0.0094	0.0263	0.0360	0.0024	0.0360	0.0000	0.0000	0.0105	0.0000	0.0000	0.0000	0.0097	0.0097
CH_4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0004	0.0000	0.0000	0.0000	0.0004	0.0004
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.6151	0.0000	0.0000	0.0000	0.5716	0.5716
CO_2	0.0003	0.0091	0.0000	0.0000	0.0000	0.0000	0.0000	0.0006	0.0000	0.0000	0.0000	0.0211	0.0211
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0007	0.0007
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3122	0.0000	0.0000	0.0000	0.2901	0.2901
H_2O	0.0104	0.2820	0.0000	0.0004	0.0000	1.0000	0.0000	0.0014	1.0000	1.0000	0.0000	0.0364	0.0364
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0081	0.0081
N_2	0.7722	0.4591	0.0140	0.9918	0.0140	0.0000	1.0000	0.0599	0.0000	0.0000	0.0000	0.0585	0.0585
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0033	0.0033
O_2	0.2077	0.2235	0.9500	0.0054	0.9500	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	37,250	1,938	225	38,900	10,865	2,424	2,019	447	2,796	1,165	0	75,202	40,232
V-L Flowrate (lb/hr)	1,074,830	51,432	7,250	1,091,540	350,168	43,673	56,553	8,949	50,331	20,982	0	1,548,350	828,347
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	402,289	402,289	45,315	0	0
Temperature (°F)	232	70	90	385	518	650	560	124	59	215	2,600	1,635	398
Pressure (psia)	190.6	16.4	125.0	460.0	740.0	740.0	815.0	516.7	14.7	14.7	614.7	614.7	574.7
Enthalpy (BTU/lb)[B]	55.3	26.8	12.5	88.0	107.7	1311.5	132.2	33.1	11,676	---	1,167	619.8	160.2
Density (lb/ft^3)	0.741	0.104	0.683	1.424	2.272	1.119	2.086	1.651	---	---	---	0.563	1.286
Molecular Weight	28.854	26.545	32.229	28.060	32.229	18.015	28.013	20.011	---	---	---	20.589	20.589

A - Solids flowrate includes dry coal; V-L flowrate includes slurry water and water from coal

B - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 3-82 Case 5 Stream Table, Shell IGCC without CO_2 Capture (continued)

	14	15	16	17	18	19	20	21	22	23	24	25	26
V-L Mole Fraction													
Ar	0.0097	0.0101	0.0101	0.0105	0.0086	0.0086	0.0003	0.0000	0.0041	0.0094	0.0094	0.0088	0.0088
CH_4	0.0004	0.0004	0.0004	0.0004	0.0003	0.0003	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.5699	0.5940	0.5940	0.6151	0.5080	0.5080	0.0112	0.0000	0.0674	0.0000	0.0000	0.0000	0.0000
CO_2	0.0217	0.0226	0.0226	0.0006	0.0005	0.0005	0.6315	0.0000	0.4947	0.0003	0.0003	0.0755	0.0755
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0002	0.0000	0.0000	0.0000	0.0000
H_2	0.2893	0.3015	0.3015	0.3122	0.2579	0.2579	0.0062	0.0000	0.0179	0.0000	0.0000	0.0000	0.0000
H_2O	0.0387	0.0015	0.0015	0.0014	0.1752	0.1752	0.0042	0.0000	0.3199	0.0108	0.0108	0.0847	0.0847
H_2S	0.0088	0.0091	0.0091	0.0000	0.0000	0.0000	0.2596	0.0000	0.0015	0.0000	0.0000	0.0000	0.0000
N_2	0.0583	0.0608	0.0608	0.0599	0.0494	0.0494	0.0870	0.0000	0.0898	0.7719	0.7719	0.7277	0.7277
NH_3	0.0032	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2076	0.2076	0.1033	0.1033
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0045	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	40,353	38,715	38,715	36,914	44,695	44,695	1,353	0	2,088	248,660	16,712	302,092	302,092
V-L Flowrate (lb/hr)	830,529	801,076	801,076	738,696	878,868	878,868	53,431	0	67,836	7,173,720	482,146	8,728,000	8,728,000
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	11,307	0	0	0	0	0
Temperature (°F)	351	95	95	124	312	385	124	344	280	59	811	1,105	270
Pressure (psia)	549.7	529.7	519.7	516.7	465.0	460.0	60.0	23.6	23.6	14.7	234.9	15.2	15.2
Enthalpy (BTU/lb)[B]	146.2	22.6	22.6	33.1	269.4	301.3	21.9	-102.1	255.2	13.8	200.3	340.0	116.4
Density (lb/ft^3)	1.300	1.841	1.807	1.651	1.111	0.998	0.378	---	0.097	0.076	0.497	0.026	0.056
Molecular Weight	20.581	20.692	20.692	20.011	19.664	19.664	39.490	---	32.491	28.849	28.849	28.892	28.892

B - Reference conditions are 32.02 F & 0.089 PSIA

Gasifier

There are two Shell dry feed, pressurized, upflow, entrained, slagging gasifiers, operating at 4.2 MPa (615 psia) and processing a total of 4,927 tonnes/day (5,431 TPD) of as-received coal. Coal reacts with oxygen and steam at a temperature of 1427°C (2600°F) to produce principally hydrogen and carbon monoxide with little carbon dioxide formed.

The gasifier includes a refractory-lined water wall that is also protected by molten slag that solidifies on the cooled walls.

Raw Gas Cooling/Particulate Removal

High-temperature heat recovery in each gasifier train is accomplished in three steps, including the gasifier jacket, which cools the syngas by maintaining the reaction temperature at 1427°C (2600°F). The product gas from the gasifier is cooled to 891°C (1635°F) by adding cooled recycled fuel gas to lower the temperature below the ash melting point. Gas (stream 12) then goes through a raw gas cooler, which lowers the gas temperature from 891°C (1635°F) to 316°C (600°F), and produces high-pressure steam for use in the steam cycle. The syngas is further cooled to 203°C (398°F) (stream 13) by heating water that is used to humidify the sweet syngas prior to the combustion turbine.

After passing through the raw gas cooler, the syngas passes through a cyclone and a raw gas candle filter where a majority of the fine particles are removed and returned to the gasifier with the coal fuel. The filter consists of an array of ceramic candle elements in a pressure vessel. Fines produced by the gasification system are recirculated to extinction. The ash that is not carried out with the gas forms slag and runs down the interior walls, exiting the gasifier in liquid form. The slag is solidified in a quench tank for disposal (stream 11). Lockhoppers are used to reduce the pressure of the solids from 4.2 to 0.1 MPa (615 to 15 psia). The syngas scrubber removes additional particulate matter further downstream.

Quench Gas Compressor

About 45 percent of the raw gas from the filter is recycled back to the gasifier as quench gas. A single-stage compressor is utilized to boost the pressure of a cooled fuel gas stream from 4.0 MPa (575 psia) to 4.2 MPa (615 psia) to provide quench gas to cool the gas stream from the gasifier.

Syngas Scrubber/Sour Water Stripper

The raw synthesis gas exiting the ceramic particulate filter at 203°C (398°F) (stream 13) then enters the scrubber for removal of chlorides and remaining particulate. The quench scrubber washes the syngas in a counter-current flow in two packed beds. The syngas leaves the scrubber saturated at a temperature of 110°C (230ºF). The quench scrubber removes essentially all traces of entrained particles, principally unconverted carbon, slag, and metals. The bottoms from the scrubber are sent to the slag removal and handling system for processing.

The sour water stripper removes NH_3, SO_2, and other impurities from the waste stream of the scrubber. The sour gas stripper consists of a sour drum that accumulates sour water from the gas scrubber and condensate from synthesis gas coolers. Sour water from the drum flows to the sour stripper, which consists of a packed column with a steam-heated reboiler. Sour gas is stripped from the liquid and sent to the sulfur recovery unit. Remaining water is sent to wastewater treatment.

COS Hydrolysis, Mercury Removal and Acid Gas Removal

H_2S and COS are at significant concentrations, requiring removal for the power plant to achieve the low design level of SO_2 emissions. H_2S is removed in an acid gas removal process; however, because COS is not readily removable, it is first catalytically converted to H_2S in a COS hydrolysis unit.

Following the water scrubber, the gas is reheated to 177°C (350°F) and fed to the COS hydrolysis reactor. The COS in the sour gas is hydrolyzed with steam over a catalyst bed to H_2S, which is more easily removed by the AGR solvent. Before the raw fuel gas can be treated in the AGR process (stream 14), it must be cooled to about 35°C (95°F). During this cooling through a series of heat exchangers, part of the water vapor condenses. This water, which contains some NH_3, is sent to the sour water stripper. The cooled syngas (stream 15) then passes through a carbon bed to remove 95 percent of the Hg (Section 3.1.4).

The Sulfinol process, developed by Shell in the early 1960s, is a combination process that uses a mixture of amines and a physical solvent. The solvent consists of an aqueous amine and sulfolane. Sulfinol-D uses diisopropanolamine (DIPA), while Sulfinol-M uses MDEA. The mixed solvents allow for better solvent loadings at high acid gas partial pressures and higher solubility of COS and organic sulfur compounds than straight aqueous amines. Sulfinol-M was selected for this application.

The sour syngas is fed directly into an HP contactor. The HP contactor is an absorption column in which the H_2S, COS, CO_2, and small amounts of H_2 and CO are removed from the gas by the Sulfinol solvent. The overhead gas stream from the HP contactor is then washed with water in the sweet gas scrubber before leaving the unit as the feed gas to the sulfur polishing unit.

The rich solvent from the bottom of the HP contactor flows through a hydraulic turbine and is flashed in the rich solvent flash vessel. The flashed gas is then scrubbed in the LP contactor with lean solvent to remove H_2S and COS. The overhead from the LP contactor is flashed in the LP KO drum. This gas can be used as a utility fuel gas, consisting primarily of H_2 and CO, at 0.8 MPa (118 psia) and 38°C (101°F). The solvent from the bottom of the LP contactor is returned to the rich solvent flash vessel.

Hot, lean solvent in the lean/rich solvent exchanger then heats the flashed rich solvent before entering the stripper. The stripper strips the H_2S, COS, and CO_2 from the solvent at low pressure with heat supplied through the stripper reboiler. The acid gas stream to sulfur recovery/tail gas cleanup is recovered as the flash gas from the stripper accumulator. The lean solvent from the bottom of the stripper is cooled in the lean/rich solvent exchanger and the lean solvent cooler. Most of the lean solvent is pumped to the HP contactor. A small amount goes to the LP contactor.

The Sulfinol process removes essentially all of the CO_2 along with the H_2S and COS. The acid gas fed to the SRU contains 26 vol% H_2S and 63 vol% CO_2. The CO_2 passes through the SRU, the TGTU and ultimately is vented through the coal dryer. Since the amount of CO_2 in the syngas is small initially, this does not have a significant effect on the mass flow reaching the gas turbine. However, the costs of the sulfur recovery/tail gas cleanup are higher than for a sulfur removal process producing an acid gas stream with a higher sulfur concentration.

Claus Unit

The sulfur recovery unit is a Claus bypass type sulfur recovery unit utilizing oxygen (stream 3) instead of air and followed by an amine-based SCOT tail gas unit. The Claus plant produces molten sulfur (stream 21) by reacting approximately one third of the H_2S in the feed to SO_2, then reacting the H_2S and SO_2 to sulfur and water. The combination of Claus technology and SCOT tail gas technology results in an overall sulfur recovery exceeding 99 percent.

Utilizing oxygen instead of air in the Claus plant reduces the overall cost of the sulfur recovery plant. The sulfur plant produces approximately 123 tonnes/day (136 TPD) of elemental sulfur. Feed for this case consists of acid gas from both the acid gas cleanup unit (stream 20) and a vent stream from the sour water stripper in the gasifier section. Vent gas from the tail gas treatment unit is combined with a slipstream of clean syngas (stream 8), passed through an incinerator, and the hot, nearly inert incinerator off gas is used to dry coal before being vented to the atmosphere.

In the furnace waste heat boiler, 12,283 kg/h (27,080 lb/h) of 3.6 MPa (525 psia) steam are generated. This steam is used to satisfy all Claus process preheating and reheating requirements as well as to provide some steam to the medium-pressure steam header. The sulfur condensers produce 0.34 MPa (50 psig) steam for the low-pressure steam header.

Power Block

Clean syngas exiting the Sulfinol absorber (stream 17) is humidified because there is not sufficient nitrogen from the ASU to provide the level of dilution required. The moisturized syngas (stream 18) is reheated (stream 19), further diluted with nitrogen from the ASU (stream 4) and steam, and enters the advanced F Class combustion turbine (CT) burner. The CT compressor provides combustion air to the burner and also 31 percent of the air requirements in the ASU (stream 24). The exhaust gas exits the CT at 596°C (1,105°F) (stream 25) and enters the HRSG where additional heat is recovered until the flue gas exits the HRSG at 132°C (270°F) (stream 26) and is discharged through the plant stack. The steam raised in the HRSG is used to power an advanced, commercially available steam turbine using a 12.4 MPa/566°C/566°C (1800 psig/1050°F/1050°F) steam cycle.

Air Separation Unit (ASU)

The ASU is designed to produce a nominal output of 3,900 tonnes/day (4,290 TPD) of 95 mole percent O_2 for use in the gasifier (stream 5) and sulfur recovery unit (stream 3). The plant is designed with two production trains. The air compressor is powered by an electric motor. Approximately 11,900 tonnes/day (13,100 TPD) of nitrogen are also recovered, compressed, and used as dilution in the gas turbine combustor. About 6.7 percent of the gas turbine air is used to supply approximately 31 percent of the ASU air requirements.

Balance of Plant

Balance of plant items were covered in Sections 3.1.9, 3.1.10 and 3.1.11.

3.4.3 KEY SYSTEM ASSUMPTIONS

System assumptions for Cases 5 and 6, Shell IGCC with and without CO_2 capture, are compiled in Exhibit 3-83.

Balance of Plant – Cases 5 and 6

The balance of plant assumptions are common to all cases and were presented previously in Exhibit 3-17.

Exhibit 3-83 Shell IGCC Plant Study Configuration Matrix

Case	5	6
Gasifier Pressure, MPa (psia)	4.2 (615)	4.2 (615)
O_2:Coal Ratio, kg O_2/kg dry coal	0.827	0.827
Carbon Conversion, %	99.5	99.5
Syngas HHV at Gasifier Outlet, kJ/Nm^3 (Btu/scf)	10,610 (285)	10,610 (285)
Steam Cycle, MPa/°C/°C (psig/°F/°F)	12.4/566/566 (1800/1050/1050)	12.4/538/538 (1800/1000/1000)
Condenser Pressure, mm Hg (in Hg)	51 (2.0)	51 (2.0)
Combustion Turbine	2x Advanced F Class (232 MW output each)	2x Advanced F Class (232 MW output each)
Gasifier Technology	Shell	Shell
Oxidant	95 vol% Oxygen	95 vol% Oxygen
Coal	Illinois No. 6	Illinois No. 6
Coal Feed Moisture Content, %	5	5
COS Hydrolysis	Yes	Occurs in SGS
Sour Gas Shift	No	Yes
H_2S Separation	Sulfinol-M	Selexol 1st Stage
Sulfur Removal, %	99.5	99.7
Sulfur Recovery	Claus Plant with Tail Gas Treatment / Elemental Sulfur	Claus Plant with Tail Gas Treatment / Elemental Sulfur
Particulate Control	Cyclone, Candle Filter, Scrubber, and AGR Absorber	Cyclone, Candle Filter, Scrubber, and AGR Absorber
Mercury Control	Carbon Bed	Carbon Bed
NOx Control	MNQC (LNB), N_2 Dilution, Humidification and steam dilution	MNQC (LNB), N_2 Dilution and Humidification
CO_2 Separation	N/A	Selexol 2nd Stage
CO_2 Capture	N/A	90.8% from Syngas
CO_2 Sequestration	N/A	Off-site Saline Formation

3.4.4 SPARING PHILOSOPHY

The sparing philosophy for Cases 5 and 6 is provided below. Single trains are utilized throughout with exceptions where equipment capacity requires an additional train. There is no redundancy other than normal sparing of rotating equipment.

The plant design consists of the following major subsystems:

- Two air separation units (2 x 50%)
- Two trains of coal drying and dry feed systems (2 x 50%)
- Two trains of gasification, including gasifier, synthesis gas cooler, cyclone, and barrier filter (2 x 50%).
- Two trains of syngas clean-up process (2 x 50%).
- Two trains of Sulfinol-M acid gas gas removal in Case 5 and two-stage Selexol in Case 6 (2 x 50%),
- One train of Claus-based sulfur recovery (1 x 100%).
- Two combustion turbine/HRSG tandems (2 x 50%).
- One steam turbine (1 x 100%).

3.4.5 CASE 5 PERFORMANCE RESULTS

The plant produces a net output of 636 MWe at a net plant efficiency of 41.1 percent (HHV basis). Shell has reported expected efficiencies using bituminous coal of around 44-45 percent (HHV basis), although this value excluded the net power impact of coal drying. [52] Accounting for coal drying would reduce the efficiency by only about 0.5-1 percentage points so the efficency results for the Shell case are still lower in this study than reported by the vendor.

Overall performance for the entire plant is summarized in Exhibit 3-84 which includes auxiliary power requirements. The ASU accounts for over 76 percent of the total auxiliary load distributed between the main air compressor, the oxygen compressor, the nitrogen compressor, and ASU auxiliaries. The cooling water system, including the circulating water pumps and cooling tower fan, accounts for over 4 percent of the auxiliary load, and the BFW pumps account for an additional 3.6 percent. All other individual auxiliary loads are less than 3 percent of the total.

Exhibit 3-84 Case 5 Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine Power	464,030
Steam Turbine Power	283,990
TOTAL POWER, kWe	**748,020**
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	430
Coal Milling	2,110
Slag Handling	540
Air Separation Unit Auxiliaries	1,000
Air Separation Unit Main Air Compressor	41,630
Oxygen Compressor	10,080
Nitrogen Compressor	37,010
Syngas Recycle Compressor	1,650
Incinerator Air Blower	160
Boiler Feedwater Pumps	4,670
Condensate Pump	230
Flash Bottoms Pump	200
Circulating Water Pumps	3,150
Cooling Tower Fans	1,630
Scrubber Pumps	120
Sulfinol Unit Auxiliaries	660
Gas Turbine Auxiliaries	1,000
Steam Turbine Auxiliaries	100
Claus Plant/TGTU Auxiliaries	250
Miscellaneous Balance of Plant (Note 1)	3,000
Transformer Loss	2,550
TOTAL AUXILIARIES, kWe	**112,170**
NET POWER, kWe	**635,850**
Net Plant Efficiency, % (HHV)	41.1
Net Plant Heat Rate (Btu/kWh)	8,306
CONDENSER COOLING DUTY 10^6 kJ/h (10^6 Btu/h)	**1,401 (1,329)**
CONSUMABLES	
As-Received Coal Feed, kg/h (lb/h)	205,305 (452,620)
Thermal Input, kWt	1,547,493
Raw Water Usage, m^3/min (gpm)	14.4 (3,792)

Note 1: Includes plant control systems, lighting, HVAC and miscellaneous low voltage loads

Environmental Performance

The environmental targets for emissions of emissions of Hg, NOx, SO_2 and particulate matter were presented in Section 2.4. A summary of the plant air emissions for Case 5 is presented in Exhibit 3-85.

Exhibit 3-85 Case 5 Air Emissions

	kg/GJ ($lb/10^6$ Btu)	Tonne/year (ton/year) 80% capacity factor	kg/MWh (lb/MWh)
SO_2	0.0053 (0.0124)	209 (230)	0.040 (0.088)
NO_X	0.025 (0.058)	982 (1,082)	0.187 (0.413)
Particulates	0.003 (0.0071)	119 (131)	0.023 (0.050)
Hg	$0.25x10^{-6}$ ($0.57x10^{-6}$)	0.010 (0.011)	$1.8x10^{-6}$ ($4.0x10^{-6}$)
CO_2	85.9 (200)	3,351,000 (3,694,000)	639 (1,409)
CO_2[1]			752 (1,658)

[1] CO_2 emissions based on net power instead of gross power

The low level of SO_2 emissions is achieved by capture of the sulfur in the gas by the Sulfinol-M AGR process. The AGR process removes over 99 percent of the sulfur compounds in the fuel gas down to a level of less than 30 ppmv. This results in a concentration in the flue gas of less than 4 ppmv. The H_2S-rich regeneration gas from the AGR system is fed to a Claus plant, producing elemental sulfur. The Claus plant tail gas is treated using an amine based system to capture most of the remaining sulfur. The cleaned gas from the tail gas treatment unit is combined with a slipstream of clean syngas, passed through an incinerator, and the hot, inert incinerator offgas is used to dry coal prior to being vented to atmosphere. The SO_2 emissions in Exhibit 3-85 include both the stack emissions and the coal dryer emissions.

NO_X emissions are limited by the use of nitrogen dilution, humidification and steam dilution to 15 ppmvd (as NO_2 @ 15 percent O_2). Ammonia in the syngas is removed with process condensate prior to the low-temperature AGR process and destroyed in the Claus plant burner. This helps lower NO_X levels as well.

Particulate discharge to the atmosphere is limited to extremely low values by the use of a cyclone and a barrier filter in addition to the syngas scrubber and the gas washing effect of the AGR absorber. The particulate emissions represent filterable particulate only.

Ninety five percent of the mercury is captured from the syngas by an activated carbon bed. CO_2 emissions represent the uncontrolled discharge from the process.

The carbon balance for the plant is shown in Exhibit 3-86. The carbon input to the plant consists of carbon in the air in addition to carbon in the coal. Carbon in the air is not neglected here since the Aspen model accounts for air components throughout. Carbon leaves the plant as unburned carbon in the slag, as dissolved CO_2 in the wastewater blowdown stream, and as CO_2 in the stack gas, ASU vent gas and coal dryer vent gas. Carbon in the wastewater blowdown stream is calculated by difference to close the material balance.

Exhibit 3-86 Case 5 Carbon Balance

Carbon In, kg/hr (lb/hr)		Carbon Out, kg/hr (lb/hr)	
Coal	130,882 (288,545)	**Slag**	656 (1,446)
Air (CO_2)	471 (1,039)	**Stack Gas**	124,162 (273,731)
		ASU Vent	96 (212)
		Coal Dryer	6,252 (13,783)
		Wastewater	187 (412)
Total	131,353 (289,584)	**Total**	131,353 (289,584)

Exhibit 3-87 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered in the Claus plant, dissolved SO_2 in the wastewater blowdown stream, sulfur in the coal drying gas, and sulfur emitted in the stack gas. Sulfur in the slag is considered to be negligible, and the sulfur content of the blowdown stream is calculated by difference to close the material balance. The total sulfur capture is represented by the following fraction:

(Sulfur byproduct/Sulfur in the coal) or
(11,307/11,361) or
99.5 percent

Exhibit 3-87 Case 5 Sulfur Balance

Sulfur In, kg/hr (lb/hr)		Sulfur Out, kg/hr (lb/hr)	
Coal	5,153 (11,361)	**Elemental Sulfur**	5,129 (11,307)
		Stack Gas	14 (30)
		Coal Dryer Vent	1 (3)
		Wastewater	9 (21)
Total	5,153 (11,361)	**Total**	5,153 (11,361)

Exhibit 3-88 shows the overall water balance for the plant. Raw water is obtained from groundwater (50 percent) and from municipal sources (50 percent). Water demand represents the total amount of water required for a particular process. Some water is recovered within the process, primarily as syngas condensate, and that water is re-used as internal recycle. Raw water makeup is the difference between water demand and internal recycle.

Exhibit 3-88 Case 5 Water Balance

Water Use	Water Demand, m^3/min (gpm)	Internal Recycle, m^3/min (gpm)	Raw Water Makeup, m^3/min (gpm)
Gasifier Steam	0.3 (87)	0	0.3 (87)
Humidifier	1.1 (293)	0	1.1 (293)
Slag Handling	0.5 (118)	0.5 (118)	0
Scrubber	0.2 (61)	0	0.2 (61)
CT Steam Dilution	0.5 (132)	0	0.5 (132)
BFW Makeup	0.2 (39)	0	0.2 (39)
Cooling Tower Makeup	12.2 (3,233)	0.2 (54)	12.0 (3,180)
Total	**15.0 (3,963)**	**0.7 (171)**	**14.3 (3,792)**

Heat and Mass Balance Diagrams

Heat and mass balance diagrams are shown for the following subsystems in Exhibit 3-89 through Exhibit 3-93:

- Coal gasification and air separation unit
- Syngas cleanup
- Sulfur recovery and tail gas recycle
- Combined cycle power generation
- Steam and feedwater

An overall plant energy balance is provided in tabular form in Exhibit 3-61. The power out is the combined combustion turbine and steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 3-84) is calculated by multiplying the power out by a combined generator efficiency of 98.3 percent.

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Exhibit 3-89 Case 5 Coal Gasification and Air Separation Unit Heat and Mass Balance Schematic

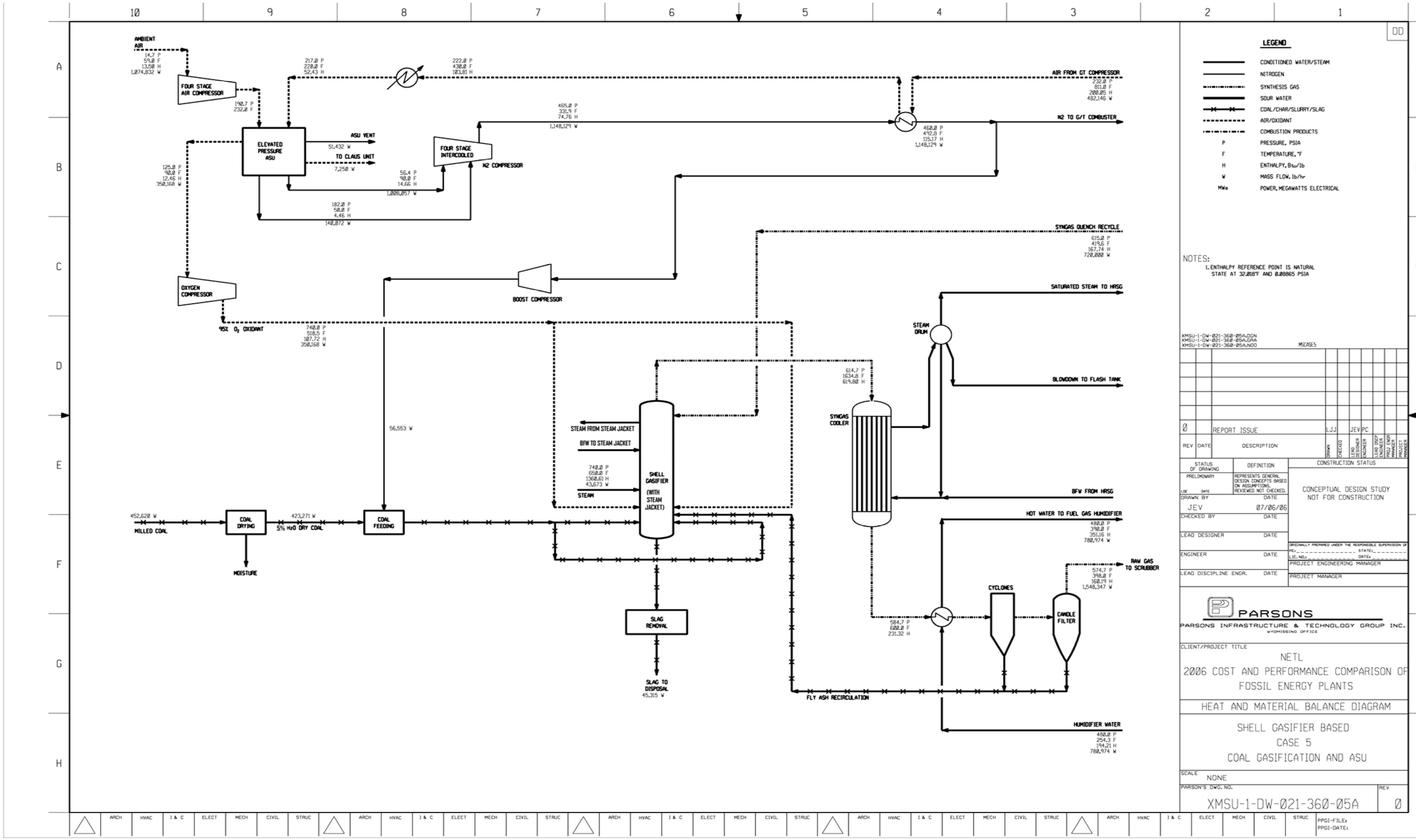

Exhibit 3-90 Case 5 Syngas Cleanup Heat and Mass Balance Schematic

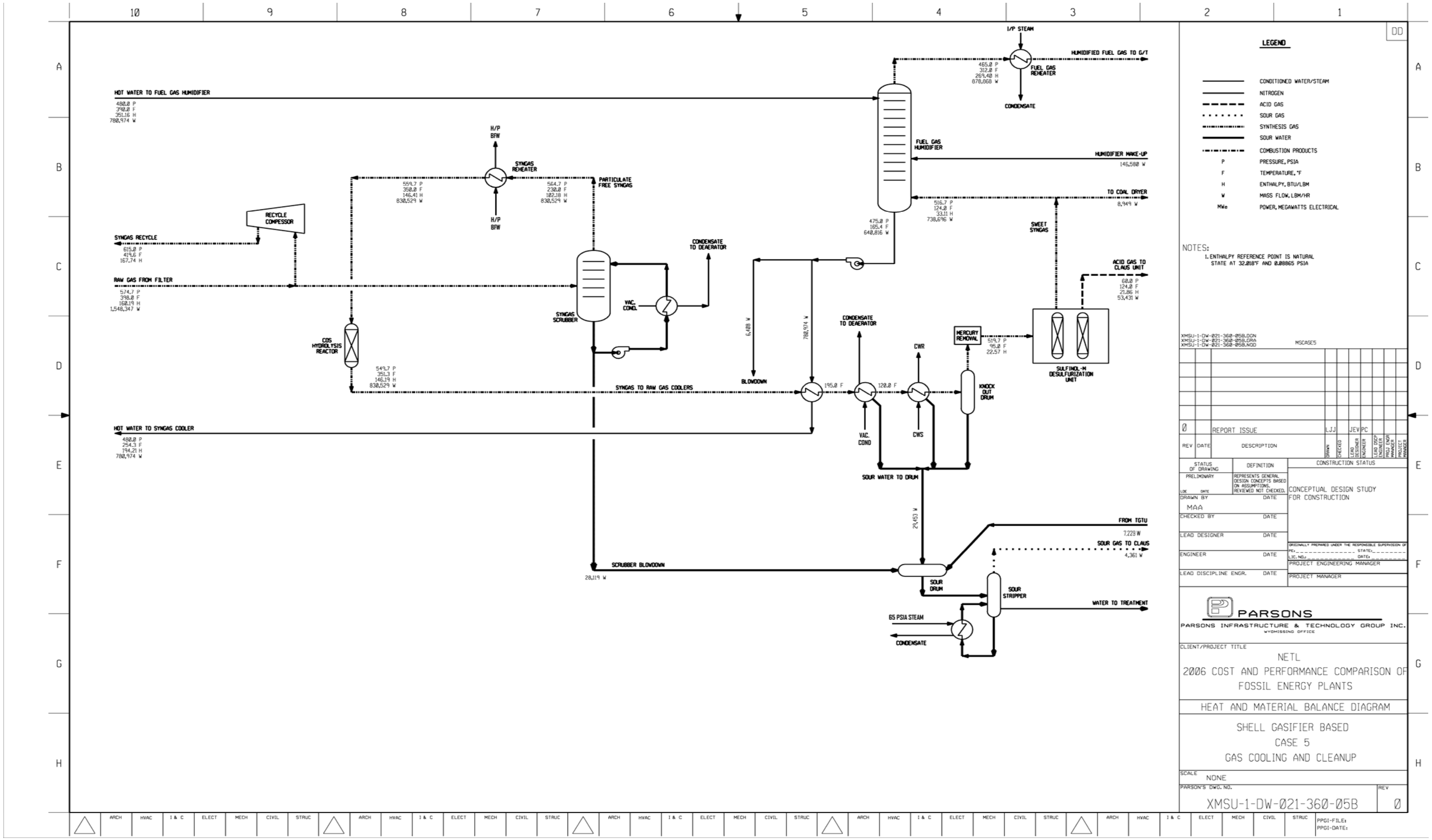

Exhibit 3-91 Case 5 Sulfur Recovery and Tail Gas Recycle Heat and Mass Balance Schematic

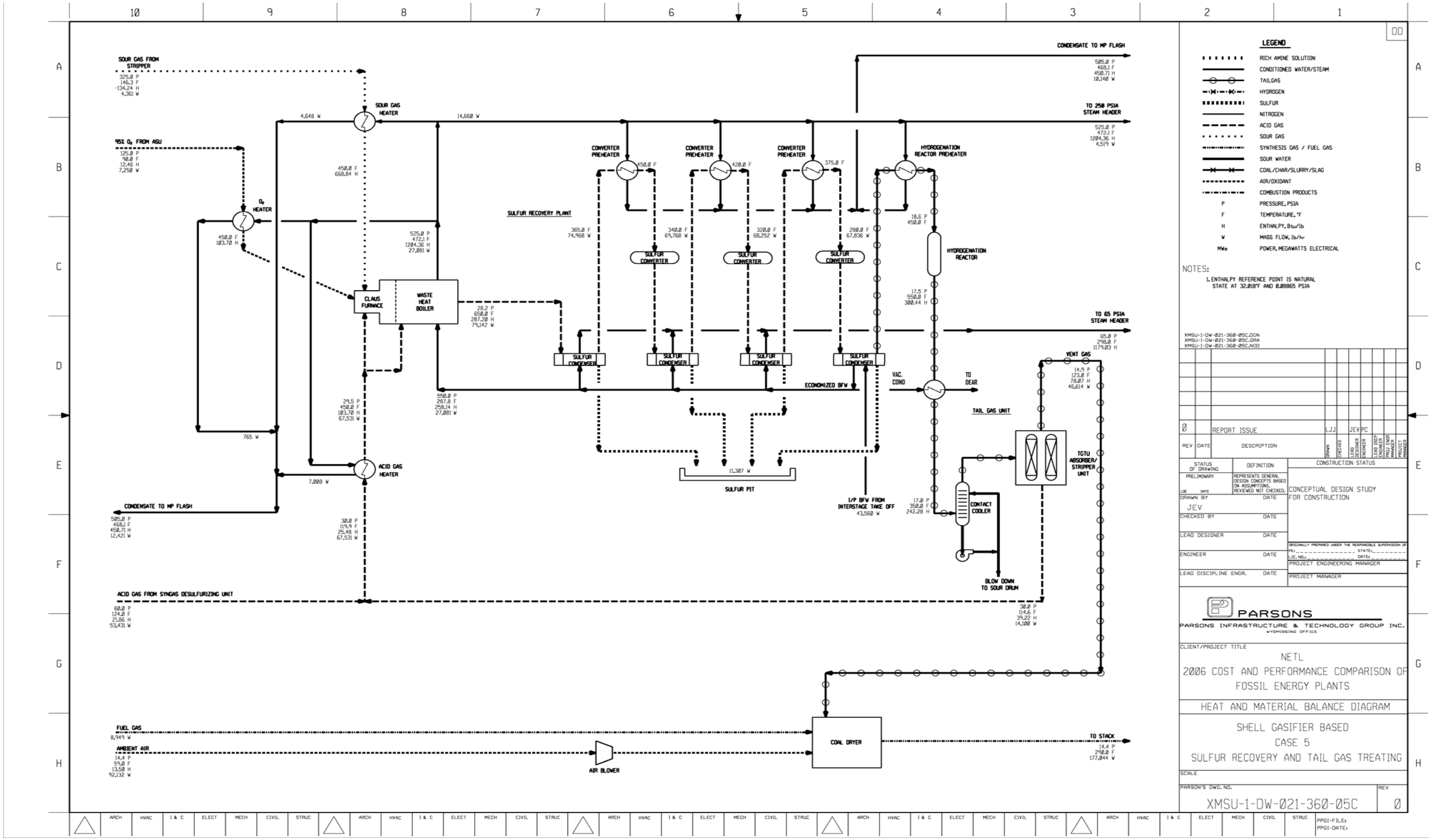

Exhibit 3-92 Case 5 Combined Cycle Power Generation Heat and Mass Balance Schematic

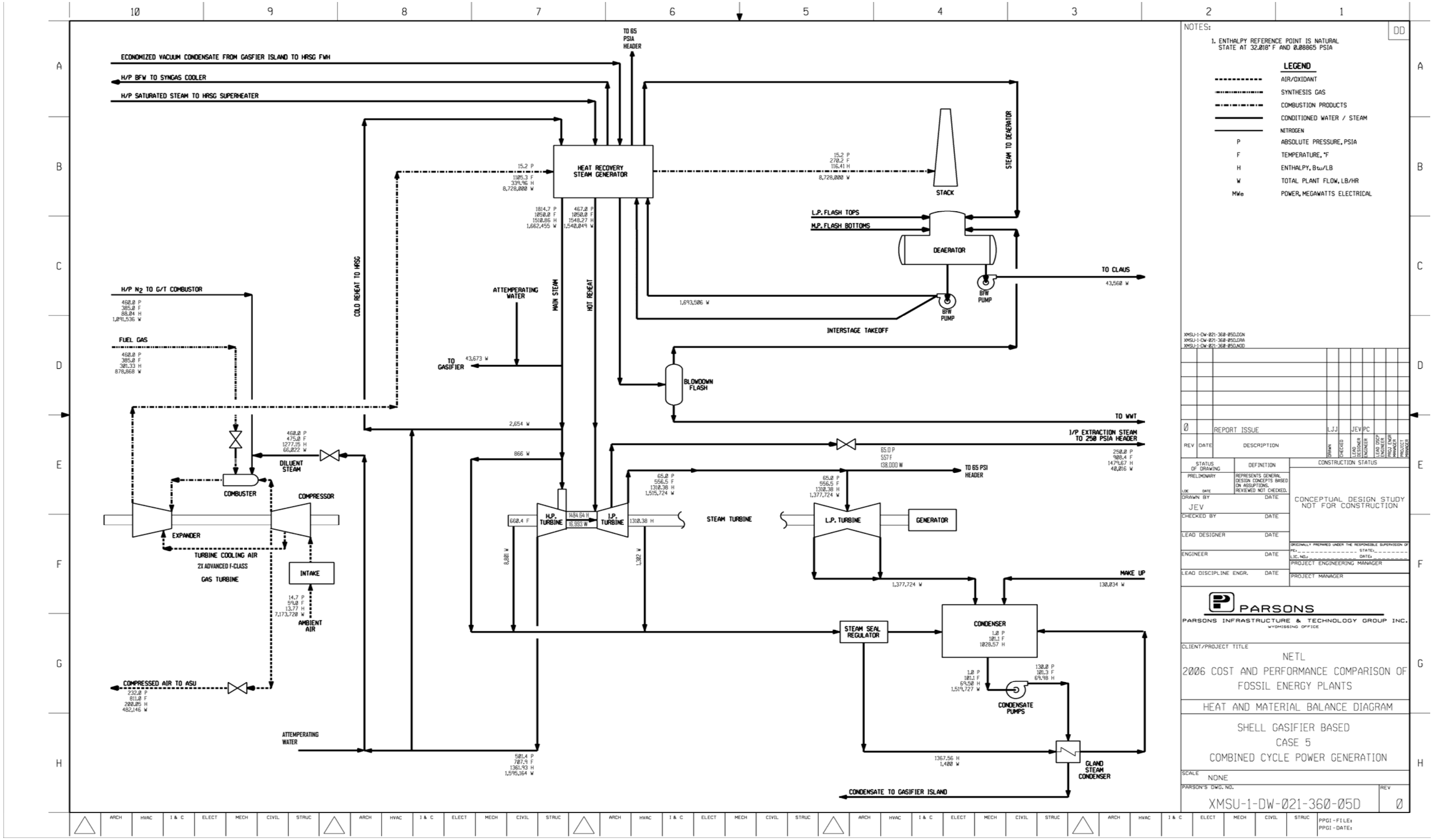

Exhibit 3-93 Case 5 Steam and Feedwater Heat and Mass Balance Schematic

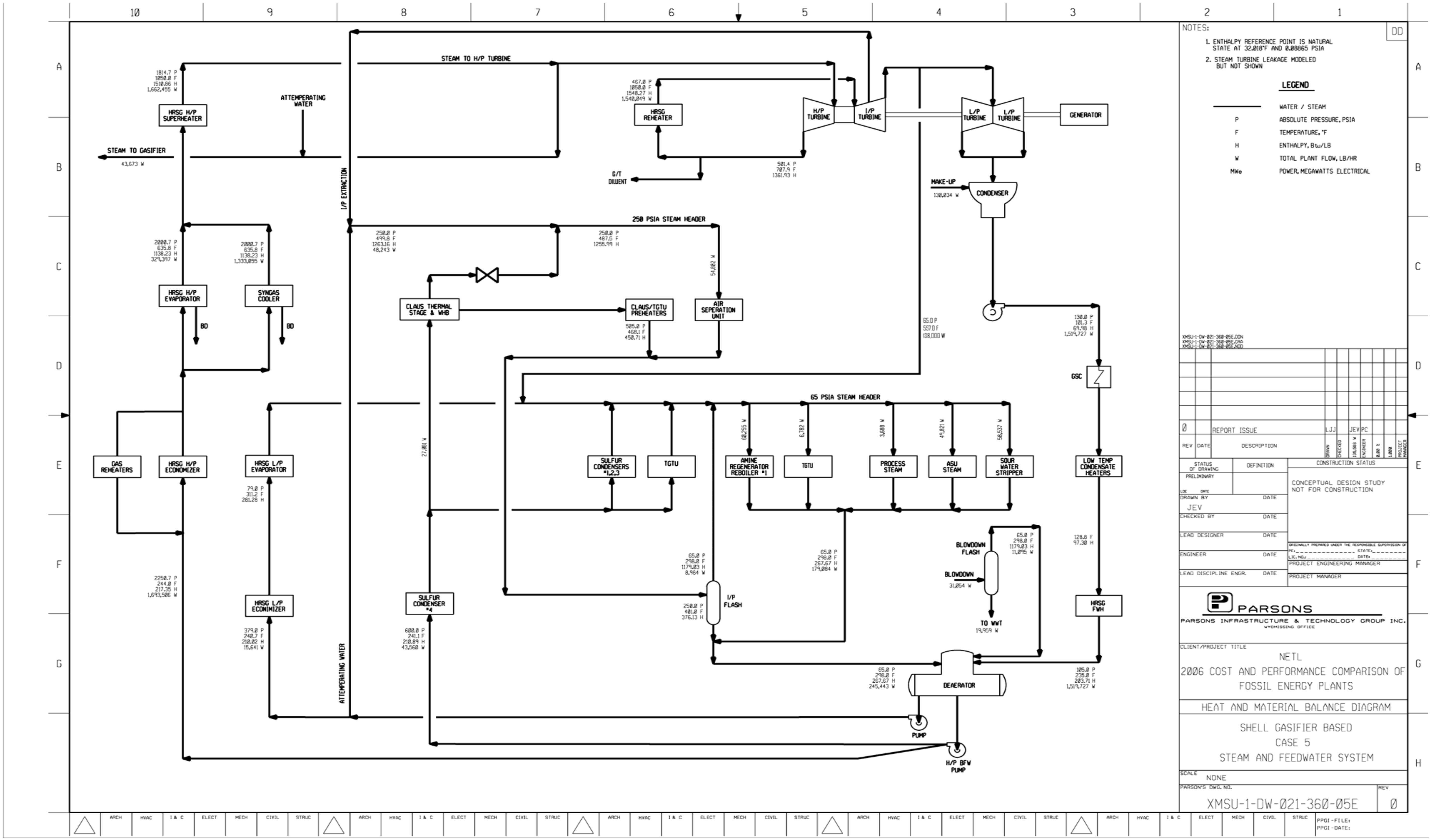

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Exhibit 3-94 Case 5 Overall Energy Balance (0°C [32°F] Reference)

	HHV	Sensible + Latent	Power	Total
Heat In (MMBtu/hr)				
Coal	5,280.2	4.4		5,284.6
ASU Air		14.5		14.5
CT Air		98.8		98.8
Incinerator Air		1.2		1.2
Water		9.4		9.4
Auxiliary Power			382.7	382.7
Totals	**5,280.2**	**128.4**	**382.7**	**5,791.3**
Heat Out (MMBtu/hr)				
ASU Intercoolers		171.4		171.4
ASU Vent		1.4		1.4
Slag	20.4	32.5		52.9
Sulfur	45.0	(1.2)		43.8
Dryer Stack Gas		53.1		53.1
HRSG Flue Gas		1015.9		1,015.9
Condenser		1,329.0		1,329.0
Process Losses		526.1		520.2
Power			2,597.6	2,597.6
Totals	**65.4**	**3,128.3**	**2,597.6**	**5,791.3**

(1) Process Losses are calculated by difference and reflect various gasification, turbine, HRSG and other heat and work losses. Aspen flowsheet balance is within 0.5 percent.

3.4.6 CASE 5 - MAJOR EQUIPMENT LIST

Major equipment items for the Shell gasifier with no CO_2 capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 3.4.7. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

ACCOUNT 1 COAL HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	181 tonne (200 ton)	2	0
2	Feeder	Belt	572 tonne/h (630 tph)	2	0
3	Conveyor No. 1	Belt	1,134 tonne/h (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,134 tonne/h (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,134 tonne/h (1,250 tph)	1	0
8	Reclaim Hopper	N/A	45 tonne (50 ton)	2	1
9	Feeder	Vibratory	172 tonne/h (190 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	336 tonne/h (370 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	172 tonne (190 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3" x 0 - 1-1/4" x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	336 tonne/h (370 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	336 tonne/h (370 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	726 tonne (800 ton)	3	0

ACCOUNT 2 COAL PREPARATION AND FEED

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Feeder	Vibratory	73 tonne/h (80 tph)	3	0
2	Conveyor No. 6	Belt w/tripper	227 tonne/h (250 tph)	1	0
3	Roller Mill Feed Hopper	Dual Outlet	454 tonne (500 ton)	1	0
4	Weigh Feeder	Belt	109 tonne/h (120 tph)	2	0
5	Coal Drying and Pulverization	Rotary	109 tonne/h (120 tph)	2	0

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	590,529 liters (156,000 gal)	2	0
2	Condensate Pumps	Vertical canned	6,360 lpm @ 91 m H2O (1,680 gpm @ 300 ft H2O)	2	1
3	Deaerator (integral w/ HRSG)	Horizontal spray type	443,160 kg/h (977,000 lb/h)	2	0
4	Intermediate Pressure Feedwater Pump	Horizontal centrifugal, single stage	151 lpm @ 302 m H2O (40 gpm @ 990 ft H2O)	2	1
5	High Pressure Feedwater Pump No. 1	Barrel type, multi-stage, centrifugal	HP water: 7,344 lpm @ 1,890 m H2O (1,940 gpm @ 6,200 ft H2O)	2	1
6	High Pressure Feedwater Pump No. 2	Barrel type, multi-stage, centrifugal	IP water: 1,060 lpm @ 223 m H2O (280 gpm @ 730 ft H2O)	2	1
7	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/h, 2.8 MPa, 343°C (40,000 lb/h, 400 psig, 650°F)	1	0
8	Service Air Compressors	Flooded Screw	28 m3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
9	Instrument Air Dryers	Duplex, regenerative	28 m3/min (1,000 scfm)	2	1
10	Closed Cylce Cooling Heat Exchangers	Plate and frame	58 MMkJ/h (55 MMBtu/h) each	2	0
11	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,820 lpm @ 21 m H2O (5,500 gpm @ 70 ft H2O)	2	1
12	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 107 m H2O (1,000 gpm @ 350 ft H2O)	1	1
13	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 76 m H2O (700 gpm @ 250 ft H2O)	1	1
14	Raw Water Pumps	Stainless steel, single suction	7,987 lpm @ 18 m H2O (2,110 gpm @ 60 ft H2O)	2	1
15	Filtered Water Pumps	Stainless steel, single suction	1,590 lpm @ 49 m H2O (420 gpm @ 160 ft H2O)	2	1
16	Filtered Water Tank	Vertical, cylindrical	768,445 liter (203,000 gal)	2	0
17	Makeup Water Demineralizer	Anion, cation, and mixed bed	151 lpm (40 gpm)	2	0
18	Liquid Waste Treatment System		10 years, 24-hour storm	1	0

ACCOUNT 4 GASIFIER, ASU AND ACCESSORIES INCLUDING LOW TEMPERATURE HEAT RECOVERY AND FUEL GAS SATURATION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gasifier	Pressurized dry-feed, entrained bed	2,722 tonne/day, 4.2 MPa (3,000 tpd, 615 psia)	2	0
2	Synthesis Gas Cooler	Convective spiral-wound tube boiler	386,461 kg/h (852,000 lb/h)	2	0
3	Synthesis Gas Cyclone	High efficiency	207,292 kg/h (457,000 lb/h) Design efficiency 90%	2	0
4	Candle Filter	Pressurized filter with pulse-jet cleaning	metallic filters	2	0
5	Syngas Scrubber Including Sour Water Stripper	Vertical upflow	206,838 kg/h (456,000 lb/h)	2	0
6	Raw Gas Coolers	Shell and tube with condensate drain	276,238 kg/h (609,000 lb/h)	6	0
7	Raw Gas Knockout Drum	Vertical with mist eliminator	200,488 kg/h, 35°C, 3.7 MPa (442,000 lb/h, 95°F, 530 psia)	2	0
8	Saturation Water Economizers	Shell and tube	207,292 kg/h (457,000 lb/h)	2	0
9	Fuel Gas Saturator	Vertical tray tower	219,085 kg/h, 154°C, 3.2 MPa (483,000 lb/h, 309°F, 465 psia)	2	0
10	Saturator Water Pump	Centrifugal	2,650 lpm @ 12 m H2O (700 gpm @ 40 ft H2O)	2	2
11	Synthesis Gas Reheater	Shell and tube	219,085 kg/h (483,000 lb/h)	2	0
12	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	206,838 kg/h (456,000 lb/h) syngas	2	0
13	ASU Main Air Compressor	Centrifugal, multi-stage	3,681 m3/min @ 1.3 MPa (130,000 scfm @ 190 psia)	2	0
14	Cold Box	Vendor design	2,177 tonne/day (2,400 tpd) of 95% purity oxygen	2	0
15	Oxygen Compressor	Centrifugal, multi-stage	1,076 m3/min @ 5.1 MPa (38,000 scfm @ 740 psia)	2	0
16	Nitrogen Compressor	Centrifugal, multi-stage	3,540 m3/min @ 3.4 MPa (125,000 scfm @ 490 psia)	2	0
17	Nitrogen Boost Compressor	Centrifugal, multi-stage	481 m3/min @ 2.3 MPa (17,000 scfm @ 340 psia)	2	0
18	Extraction Air Heat Exchanger	Gas-to-gas, vendor design	120,202 kg/h, 433°C, 1.6 MPa (265,000 lb/h, 811°F, 232 psia)	2	0

ACCOUNT 5 SYNGAS CLEANUP

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Mercury Adsorber	Sulfated carbon bed	200,034 kg/h (441,000 lb/h) 35°C (95°F) 3.7 MPa (530 psia)	2	0
2	Sulfur Plant	Claus type	135 tonne/day (149 tpd)	1	0
3	COS Hydrolysis Reactor	Fixed bed, catalytic	207,292 kg/h (457,000 lb/h) 177°C (350°F) 3.9 MPa (560 psia)	2	0
4	Acid Gas Removal Plant	Sulfinol	200,034 kg/h (441,000 lb/h) 51°C (124°F) 3.6 MPa (520 psia)	2	0
5	Tail Gas Treatment Unit	Proprietary amine, absorber/stripper	30,255 kg/h (66,700 lb/h) 49°C (120°F) 0.1 MPa (16.4 psia)	1	0
6	Tail Gas Treatment Incinerator	N/A	64 MMkJ/h (61 MMBtu/h)	1	0

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.
1	Gas Turbine	Advanced F class	232 MW	2
2	Gas Turbine Generator	TEWAC	260 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	2

ACCOUNT 7 HRSG, DUCTING AND STACK

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	CS plate, type 409SS liner	76 m (250 ft) high x 8.4 m (28 ft) diameter	1	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	Main steam - 414,742 kg/h, 12.4 MPa/566°C (914,348 lb/h, 1,800 psig/1,050°F) Reheat steam - 384,205 kg/h, 3.1 MPa/566°C (847,027 lb/h, 452 psig/1,050°F)	2	0

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	299 MW 12.4 MPa/566°C/566°C (1800 psig/ 1050°F/1050°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitiation	330 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Steam Bypass	One per HRSG	50% steam flow @ design steam conditions	2	0
4	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,539 MMkJ/h (1,460 MMBtu/h), Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1	0

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	314,192 lpm @ 30 m (83,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT / 1760 MMkJ/h (1670 MMBtu/h) heat duty	1	0

ACCOUNT 10 SLAG RECOVERY AND HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Slag Quench Tank	Water bath	215,770 liters (57,000 gal)	2	0
2	Slag Crusher	Roll	11 tonne/h (12 tph)	2	0
3	Slag Depressurizer	Lock Hopper	11 tonne/h (12 tph)	2	0
4	Slag Receiving Tank	Horizontal, weir	140,061 liters (37,000 gal)	2	0
5	Black Water Overflow Tank	Shop fabricated	68,138 liters (18,000 gal)	2	
6	Slag Conveyor	Drag chain	11 tonne/h (12 tph)	2	0
7	Slag Separation Screen	Vibrating	11 tonne/h (12 tph)	2	0
8	Coarse Slag Conveyor	Belt/bucket	11 tonne/h (12 tph)	2	0
9	Fine Ash Settling Tank	Vertical, gravity	211,985 liters (56,000 gal)	2	0
10	Fine Ash Recycle Pumps	Horizontal centrifugal	38 lpm @ 14 m H2O (10 gpm @ 46 ft H2O)	2	2
11	Grey Water Storage Tank	Field erected	68,138 liters (18,000 gal)	2	0
12	Grey Water Pumps	Centrifugal	227 lpm @ 433 m H2O (60 gpm @ 1,420 ft H2O)	2	2
13	Slag Storage Bin	Vertical, field erected	816 tonne (900 tons)	2	0
14	Unloading Equipment	Telescoping chute	91 tonne/h (100 tph)	1	0

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	24 kV/345 kV, 260 MVA, 3-ph, 60 Hz	2	0
2	STG Transformer	Oil-filled	24 kV/345 kV, 200 MVA, 3-ph, 60 Hz	1	0
3	Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 124 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 19 MVA, 3-ph, 60 Hz	1	1
5	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	2	0
6	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
7	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
8	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
9	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

ACCOUNT 12 INSTRUMENTATION AND CONTROLS

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

3.4.7 CASE 5 - COST ESTIMATING

Costs Results

The cost estimating methodology was described previously in Section 2.6. Exhibit 3-95 shows the total plant capital cost summary organized by cost account and Exhibit 3-96 shows a more detailed breakdown of the capital costs. Exhibit 3-97 shows the initial and annual O&M costs.

The estimated TPC of the Shell gasifier with no CO_2 capture is $1,977/kW. Process contingency represents 2.6 percent of the TPC and project contingency represents 13.7 percent. The 20-year LCOE is 80.5 mills/kWh.

Exhibit 3-95 Case 5 Total Plant Cost Summary

Client: USDOE/NETL **Report Date:** 05-Apr-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 05 - Shell IGCC w/o CO2
Plant Size: 635.9 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	$12,864	$2,398	$10,080	$0	$0	**$25,343**	$2,296	$0	$5,528	**$33,166**	$52
2	COAL & SORBENT PREP & FEED	$101,770	$8,108	$17,105	$0	$0	**$126,983**	$11,023	$0	$27,601	**$165,607**	$260
3	FEEDWATER & MISC. BOP SYSTEMS	$9,612	$8,441	$8,983	$0	$0	**$27,035**	$2,523	$0	$6,636	**$36,194**	$57
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries	$133,051	$0	$58,510	$0	$0	**$191,560**	$17,125	$26,889	$36,009	**$271,583**	$427
4.2	Syngas Cooling (w/4.1)	w/4.1	$0	w/4.1	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.3	ASU/Oxidant Compression	$135,222	$0	w/equip.	$0	$0	**$135,222**	$12,870	$0	$14,809	**$162,901**	$256
4.4-4.9	Other Gasification Equipment	$15,596	$8,787	$10,765	$0	$0	**$35,147**	$3,316	$0	$8,369	**$46,833**	$74
	SUBTOTAL 4	**$283,868**	**$8,787**	**$69,274**	**$0**	**$0**	**$361,929**	**$33,312**	**$26,889**	**$59,188**	**$481,317**	**$757**
5A	Gas Cleanup & Piping	$52,340	$6,552	$37,224	$0	$0	**$96,117**	$9,164	$82	$21,477	**$126,839**	$199
5B	CO_2 REMOVAL & COMPRESSION	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$82,000	$0	$5,071	$0	$0	**$87,071**	$8,191	$4,354	$9,962	**$109,578**	$172
6.2-6.9	Combustion Turbine Other	$0	$684	$762	$0	$0	**$1,446**	$135	$0	$474	**$2,055**	$3
	SUBTOTAL 6	**$82,000**	**$684**	**$5,833**	**$0**	**$0**	**$88,517**	**$8,326**	**$4,354**	**$10,436**	**$111,632**	**$176**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$34,073	$0	$4,848	$0	$0	**$38,921**	$3,674	$0	$4,260	**$46,855**	$74
7.2-7.9	Ductwork and Stack	$3,174	$2,235	$2,996	$0	$0	**$8,405**	$776	$0	$1,494	**$10,675**	$17
	SUBTOTAL 7	**$37,247**	**$2,235**	**$7,844**	**$0**	**$0**	**$47,326**	**$4,450**	**$0**	**$5,753**	**$57,529**	**$90**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$28,510	$0	$4,862	$0	$0	**$33,372**	$3,198	$0	$3,657	**$40,227**	$63
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$10,015	$966	$7,277	$0	$0	**$18,258**	$1,646	$0	$4,035	**$23,939**	$38
	SUBTOTAL 8	**$38,525**	**$966**	**$12,138**	**$0**	**$0**	**$51,630**	**$4,844**	**$0**	**$7,692**	**$64,166**	**$101**
9	COOLING WATER SYSTEM	$6,512	$7,397	$6,140	$0	$0	**$20,049**	$1,841	$0	$4,525	**$26,415**	$42
10	ASH/SPENT SORBENT HANDLING SYS	$17,384	$1,343	$8,631	$0	$0	**$27,357**	$2,605	$0	$3,274	**$33,236**	$52
11	ACCESSORY ELECTRIC PLANT	$21,331	$6,784	$19,452	$0	$0	**$47,567**	$4,373	$0	$9,764	**$61,704**	$97
12	INSTRUMENTATION & CONTROL	$9,443	$1,768	$6,339	$0	$0	**$17,551**	$1,617	$878	$3,354	**$23,399**	$37
13	IMPROVEMENTS TO SITE	$3,166	$1,866	$7,871	$0	$0	**$12,903**	$1,268	$0	$4,251	**$18,422**	$29
14	BUILDINGS & STRUCTURES	$0	$6,247	$7,291	$0	$0	**$13,537**	$1,231	$0	$2,414	**$17,182**	$27
	TOTAL COST	**$676,062**	**$63,575**	**$224,205**	**$0**	**$0**	**$963,842**	**$88,874**	**$32,202**	**$171,892**	**$1,256,810**	**$1,977**

Exhibit 3-96 Case 5 Total Plant Cost Details

Client: USDOE/NETL **Report Date:** 05-Apr-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 05 - Shell IGCC w/o CO2
Plant Size: 635.9 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	$3,378	$0	$1,668	$0	$0	$5,046	$452	$0	$1,100	$6,598	$10
1.2	Coal Stackout & Reclaim	$4,365	$0	$1,069	$0	$0	$5,435	$477	$0	$1,182	$7,094	$11
1.3	Coal Conveyors	$4,059	$0	$1,058	$0	$0	$5,117	$449	$0	$1,113	$6,679	$11
1.4	Other Coal Handling	$1,062	$0	$245	$0	$0	$1,307	$114	$0	$284	$1,705	$3
1.5	Sorbent Receive & Unload	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.6	Sorbent Stackout & Reclaim	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.7	Sorbent Conveyors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.8	Other Sorbent Handling	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.9	Coal & Sorbent Hnd.Foundations	$0	$2,398	$6,040	$0	$0	$8,438	$804	$0	$1,848	$11,091	$17
	SUBTOTAL 1.	**$12,864**	**$2,398**	**$10,080**	**$0**	**$0**	**$25,343**	**$2,296**	**$0**	**$5,528**	**$33,166**	**$52**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	$38,663	$2,310	$5,692	$0	$0	$46,666	$4,033	$0	$10,140	$60,838	$96
2.2	Prepared Coal Storage & Feed	$1,831	$436	$290	$0	$0	$2,557	$219	$0	$555	$3,332	$5
2.3	Dry Coal Injection System	$60,268	$706	$5,655	$0	$0	$66,630	$5,747	$0	$14,475	$86,852	$137
2.4	Misc.Coal Prep & Feed	$1,007	$729	$2,220	$0	$0	$3,956	$363	$0	$864	$5,182	$8
2.5	Sorbent Prep Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.6	Sorbent Storage & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.7	Sorbent Injection System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.8	Booster Air Supply System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.9	Coal & Sorbent Feed Foundation	$0	$3,927	$3,247	$0	$0	$7,174	$662	$0	$1,567	$9,403	$15
	SUBTOTAL 2.	**$101,770**	**$8,108**	**$17,105**	**$0**	**$0**	**$126,983**	**$11,023**	**$0**	**$27,601**	**$165,607**	**$260**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	$3,370	$5,859	$3,095	$0	$0	$12,325	$1,137	$0	$2,692	$16,154	$25
3.2	Water Makeup & Pretreating	$505	$53	$282	$0	$0	$839	$79	$0	$276	$1,194	$2
3.3	Other Feedwater Subsystems	$1,861	$631	$568	$0	$0	$3,060	$274	$0	$667	$4,000	$6
3.4	Service Water Systems	$291	$594	$2,063	$0	$0	$2,948	$285	$0	$970	$4,203	$7
3.5	Other Boiler Plant Systems	$1,563	$600	$1,487	$0	$0	$3,650	$342	$0	$799	$4,791	$8
3.6	FO Supply Sys & Nat Gas	$300	$567	$529	$0	$0	$1,397	$134	$0	$306	$1,836	$3
3.7	Waste Treatment Equipment	$702	$0	$430	$0	$0	$1,132	$110	$0	$372	$1,614	$3
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	$1,020	$137	$528	$0	$0	$1,685	$162	$0	$554	$2,402	$4
	SUBTOTAL 3.	**$9,612**	**$8,441**	**$8,983**	**$0**	**$0**	**$27,035**	**$2,523**	**$0**	**$6,636**	**$36,194**	**$57**
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries	$133,051	$0	$58,510	$0	$0	$191,560	$17,125	$26,889	$36,009	$271,583	$427
4.2	Syngas Cooling (w/4.1)	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.3	ASU/Oxidant Compression	$135,222	$0	w/equip.	$0	$0	$135,222	$12,870	$0	$14,809	$162,901	$256
4.4	LT Heat Recovery & FG Saturation	$15,596	$0	$5,868	$0	$0	$21,464	$2,063	$0	$4,705	$28,232	$44
4.5	Misc. Gasification Equipment w/4.1 & 4.2	w/4.1&4.2	$0	w/4.1&4.2	$0	$0	$0	$0	$0	$0	$0	$0
4.6	Other Gasification Equipment	$0	$910	$371	$0	$0	$1,281	$122	$0	$281	$1,684	$3
4.8	Major Component Rigging	w/4.1&4.2	$0	w/4.1&4.2	$0	$0	$0	$0	$0	$0	$0	$0
4.9	Gasification Foundations	$0	$7,876	$4,526	$0	$0	$12,402	$1,131	$0	$3,383	$16,917	$27
	SUBTOTAL 4.	**$283,868**	**$8,787**	**$69,274**	**$0**	**$0**	**$361,929**	**$33,312**	**$26,889**	**$59,188**	**$481,317**	**$757**

Exhibit 3-96 Case 5 Total Plant Cost Details (Continued)

Client: USDOE/NETL **Report Date:** 05-Apr-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 05 - Shell IGCC w/o CO2
Plant Size: 635.9 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5A	GAS CLEANUP & PIPING											
5A.1	Sulfinol Sustem	$38,450	$0	$17,968	$0	$0	$56,417	$5,378	$0	$12,359	$74,154	$117
5A.2	Elemental Sulfur Plant	$9,353	$1,856	$12,076	$0	$0	$23,285	$2,246	$0	$5,106	$30,636	$48
5A.3	Mercury Removal	$926	$0	$705	$0	$0	$1,631	$156	$82	$374	$2,243	$4
5A.4	COS Hydrolysis	$2,564	$0	$3,351	$0	$0	$5,916	$571	$0	$1,297	$7,784	$12
5A.5	Particulate Removal	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
5A.5	Blowback Gas Systems	$1,047	$176	$99	$0	$0	$1,323	$125	$0	$289	$1,737	$3
5A.6	Fuel Gas Piping	$0	$2,272	$1,566	$0	$0	$3,838	$350	$0	$837	$5,025	$8
5A.9	HGCU Foundations	$0	$2,248	$1,460	$0	$0	$3,708	$339	$0	$1,214	$5,261	$8
	SUBTOTAL 5A.	**$52,340**	**$6,552**	**$37,224**	**$0**	**$0**	**$96,117**	**$9,164**	**$82**	**$21,477**	**$126,839**	**$199**
5B	CO2 REMOVAL & COMPRESSION											
5B.1	CO2 Removal System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5B.2	CO2 Compression & Drying	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 5B.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$82,000	$0	$5,071	$0	$0	$87,071	$8,191	$4,354	$9,962	$109,578	$172
6.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.3	Compressed Air Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.9	Combustion Turbine Foundations	$0	$684	$762	$0	$0	$1,446	$135	$0	$474	$2,055	$3
	SUBTOTAL 6.	**$82,000**	**$684**	**$5,833**	**$0**	**$0**	**$88,517**	**$8,326**	**$4,354**	**$10,436**	**$111,632**	**$176**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$34,073	$0	$4,848	$0	$0	$38,921	$3,674	$0	$4,260	$46,855	$74
7.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$0	$1,603	$1,191	$0	$0	$2,794	$246	$0	$608	$3,648	$6
7.4	Stack	$3,174	$0	$1,193	$0	$0	$4,367	$415	$0	$478	$5,261	$8
7.9	HRSG,Duct & Stack Foundations	$0	$632	$611	$0	$0	$1,243	$115	$0	$408	$1,766	$3
	SUBTOTAL 7.	**$37,247**	**$2,235**	**$7,844**	**$0**	**$0**	**$47,326**	**$4,450**	**$0**	**$5,753**	**$57,529**	**$90**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$28,510	$0	$4,862	$0	$0	$33,372	$3,198	$0	$3,657	$40,227	$63
8.2	Turbine Plant Auxiliaries	$196	$0	$450	$0	$0	$646	$63	$0	$71	$779	$1
8.3	Condenser & Auxiliaries	$4,511	$0	$1,442	$0	$0	$5,952	$565	$0	$652	$7,169	$11
8.4	Steam Piping	$5,308	$0	$3,741	$0	$0	$9,048	$772	$0	$2,455	$12,276	$19
8.9	TG Foundations	$0	$966	$1,645	$0	$0	$2,611	$246	$0	$857	$3,714	$6
	SUBTOTAL 8.	**$38,525**	**$966**	**$12,138**	**$0**	**$0**	**$51,630**	**$4,844**	**$0**	**$7,692**	**$64,166**	**$101**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$4,206	$0	$924	$0	$0	$5,130	$486	$0	$842	$6,458	$10
9.2	Circulating Water Pumps	$1,317	$0	$79	$0	$0	$1,397	$119	$0	$227	$1,743	$3
9.3	Circ.Water System Auxiliaries	$117	$0	$17	$0	$0	$134	$13	$0	$22	$169	$0
9.4	Circ.Water Piping	$0	$4,978	$1,270	$0	$0	$6,248	$553	$0	$1,360	$8,162	$13
9.5	Make-up Water System	$288	$0	$409	$0	$0	$697	$66	$0	$153	$916	$1
9.6	Component Cooling Water Sys	$582	$697	$492	$0	$0	$1,771	$164	$0	$387	$2,322	$4
9.9	Circ.Water System Foundations& Structures	$0	$1,723	$2,949	$0	$0	$4,672	$441	$0	$1,534	$6,646	$10
	SUBTOTAL 9.	**$6,512**	**$7,397**	**$6,140**	**$0**	**$0**	**$20,049**	**$1,841**	**$0**	**$4,525**	**$26,415**	**$42**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Slag Dewatering & Cooling	$15,123	$0	$7,464	$0	$0	$22,587	$2,154	$0	$2,474	$27,215	$43
10.2	Gasifier Ash Depressurization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.3	Cleanup Ash Depressurization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.4	High Temperature Ash Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.5	Other Ash Rrecovery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$511	$0	$557	$0	$0	$1,068	$103	$0	$176	$1,346	$2
10.7	Ash Transport & Feed Equipment	$691	$0	$166	$0	$0	$856	$79	$0	$140	$1,075	$2
10.8	Misc. Ash Handling Equipment	$1,059	$1,298	$388	$0	$0	$2,745	$259	$0	$451	$3,454	$5
10.9	Ash/Spent Sorbent Foundation	$0	$45	$57	$0	$0	$102	$10	$0	$33	$145	$0
	SUBTOTAL 10.	**$17,384**	**$1,343**	**$8,631**	**$0**	**$0**	**$27,357**	**$2,605**	**$0**	**$3,274**	**$33,236**	**$52**

Exhibit 3-96 Case 5 Total Plant Cost Details (Continued)

Client: USDOE/NETL **Report Date:** 05-Apr-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 05 - Shell IGCC w/o CO2
Plant Size: 635.9 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$905	$0	$902	$0	$0	$1,808	$172	$0	$198	$2,177	$3
11.2	Station Service Equipment	$3,411	$0	$320	$0	$0	$3,732	$354	$0	$409	$4,495	$7
11.3	Switchgear & Motor Control	$6,519	$0	$1,195	$0	$0	$7,714	$715	$0	$1,264	$9,693	$15
11.4	Conduit & Cable Tray	$0	$310	$10,070	$0	$0	$10,380	$1,259	$0	$2,910	$14,549	$23
11.5	Wire & Cable	$0	$5,697	$3,832	$0	$0	$9,529	$697	$0	$2,556	$12,782	$20
11.6	Protective Equipment	$0	$627	$2,378	$0	$0	$3,005	$294	$0	$495	$3,793	$6
11.7	Standby Equipment	$215	$0	$219	$0	$0	$434	$42	$0	$71	$548	$1
11.8	Main Power Transformers	$10,280	$0	$139	$0	$0	$10,419	$789	$0	$1,681	$12,889	$20
11.9	Electrical Foundations	$0	$150	$396	$0	$0	$546	$52	$0	$179	$777	$1
	SUBTOTAL 11.	**$21,331**	**$6,784**	**$19,452**	**$0**	**$0**	**$47,567**	**$4,373**	**$0**	**$9,764**	**$61,704**	**$97**
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
12.3	Steam Turbine Control	w/8.1	$0	w/8.1	$0	$0	$0	$0	$0	$0	$0	$0
12.4	Other Major Component Control	$932	$0	$649	$0	$0	$1,581	$152	$79	$272	$2,084	$3
12.5	Signal Processing Equipment	W/12.7	$0	W/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.6	Control Boards,Panels & Racks	$214	$0	$143	$0	$0	$357	$34	$18	$82	$492	$1
12.7	Computer & Accessories	$4,973	$0	$166	$0	$0	$5,139	$487	$257	$588	$6,471	$10
12.8	Instrument Wiring & Tubing	$0	$1,768	$3,700	$0	$0	$5,468	$464	$273	$1,551	$7,756	$12
12.9	Other I & C Equipment	$3,324	$0	$1,682	$0	$0	$5,006	$480	$250	$860	$6,597	$10
	SUBTOTAL 12.	**$9,443**	**$1,768**	**$6,339**	**$0**	**$0**	**$17,551**	**$1,617**	**$878**	**$3,354**	**$23,399**	**$37**
13	Improvements to Site											
13.1	Site Preparation	$0	$99	$2,139	$0	$0	$2,238	$221	$0	$738	$3,197	$5
13.2	Site Improvements	$0	$1,767	$2,366	$0	$0	$4,132	$406	$0	$1,361	$5,900	$9
13.3	Site Facilities	$3,166	$0	$3,366	$0	$0	$6,532	$641	$0	$2,152	$9,325	$15
	SUBTOTAL 13.	**$3,166**	**$1,866**	**$7,871**	**$0**	**$0**	**$12,903**	**$1,268**	**$0**	**$4,251**	**$18,422**	**$29**
14	Buildings & Structures											
14.1	Combustion Turbine Area	$0	$221	$127	$0	$0	$348	$31	$0	$76	$454	$1
14.2	Steam Turbine Building	$0	$2,337	$3,373	$0	$0	$5,710	$524	$0	$935	$7,169	$11
14.3	Administration Building	$0	$794	$584	$0	$0	$1,379	$123	$0	$225	$1,727	$3
14.4	Circulation Water Pumphouse	$0	$157	$84	$0	$0	$241	$21	$0	$39	$301	$0
14.5	Water Treatment Buildings	$0	$402	$398	$0	$0	$800	$72	$0	$131	$1,003	$2
14.6	Machine Shop	$0	$407	$282	$0	$0	$689	$61	$0	$112	$862	$1
14.7	Warehouse	$0	$657	$430	$0	$0	$1,086	$96	$0	$177	$1,360	$2
14.8	Other Buildings & Structures	$0	$393	$310	$0	$0	$704	$63	$0	$153	$920	$1
14.9	Waste Treating Building & Str.	$0	$879	$1,703	$0	$0	$2,582	$240	$0	$564	$3,386	$5
	SUBTOTAL 14.	**$0**	**$6,247**	**$7,291**	**$0**	**$0**	**$13,537**	**$1,231**	**$0**	**$2,414**	**$17,182**	**$27**
	TOTAL COST	**$676,062**	**$63,575**	**$224,205**	**$0**	**$0**	**$963,842**	**$88,874**	**$32,202**	**$171,892**	**$1,256,810**	**$1,977**

Exhibit 3-97 Case 5 Initial and Annual Operating and Maintenance Costs

INITIAL & ANNUAL O&M EXPENSES						
Case 05 - Shell IGCC w/o CO2					Cost Base (Dec)	2006
					Heat Rate-net(Btu/kWh):	8,306
					MWe-net:	636
					Capacity Factor: (%):	80
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate(base):	33.00	$/hour				
Operating Labor Burden:	30.00	% of base				
Labor O-H Charge Rate:	25.00	% of labor				
			Total			
Skilled Operator	2.0		2.0			
Operator	9.0		9.0			
Foreman	1.0		1.0			
Lab Tech's, etc.	3.0		3.0			
TOTAL-O.J.'s	15.0		15.0			
					Annual Cost $	Annual Unit Cost $/kW-net
Annual Operating Labor Cost					$5,637,060	$8.865
Maintenance Labor Cost					$12,260,125	$19.281
Administrative & Support Labor					$4,474,296	$7.037
TOTAL FIXED OPERATING COSTS					**$22,371,481**	**$35.184**
VARIABLE OPERATING COSTS						
						$/kWh-net
Maintenance Material Cost					**$22,850,084**	**$0.00513**
Consumables	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost		
Water(/1000 gallons)	0	5,460	1.03	**$0**	**$1,642,294**	**$0.00037**
Chemicals						
MU & WT Chem.(lb)	113,862	16,266	0.16	$18,764	$782,745	$0.00018
Carbon (Mercury Removal) (lb)	72,509	99	1.00	$72,509	$28,908	$0.00001
COS Catalyst (m3)	1	0.19	2,308.40	$3,042	$126,875	$0.00003
Water Gas Shift Catalyst(ft3)	0	0	475.00	$0	$0	$0.00000
Selexol Solution (gal.)	0	0	12.90	$0	$0	$0.00000
MDEA Solution (gal)	0	0	0.96	$0	$0	$0.00000
Sulfinol Solution (gal)	525	75	9.68	$5,080	$211,900	$0.00005
SCR Catalyst (m3)	0	0	0.00	$0	$0	$0.00000
Aqueous Ammonia (ton)	0	0	0.00	$0	$0	$0.00000
Claus Catalyst(ft3)	w/equip.	2.05	125.00	$0	$74,825	$0.00002
Subtotal Chemicals				**$99,395**	**$1,225,254**	**$0.00027**
Other						
Supplemental Fuel(MBtu)	0	0	0.00	$0	$0	$0.00000
Gases,N2 etc.(/100scf)	0	0	0.00	$0	$0	$0.00000
L.P. Steam(/1000 pounds)	0	0	0.00	$0	$0	$0.00000
Subtotal Other				**$0**	**$0**	**$0.00000**
Waste Disposal						
Spent Mercury Catalyst (lb)	0	99	0.40	$0	$11,609	$0.00000
Flyash (ton)	0	0	0.00	$0	$0	$0.00000
Bottom Ash(ton)	0	544	15.45	$0	$2,453,209	$0.00055
Subtotal-Waste Disposal				**$0**	**$2,464,819**	**$0.00055**
By-products & Emissions						
Sulfur(tons)	0	136	0.00	$0	$0	$0.00000
Subtotal By-Products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$99,395**	**$28,182,450**	**$0.00632**
Fuel(ton)	162,977	5,433	42.11	**$6,862,984**	**$66,799,712**	**$0.01499**

3.4.8 CASE 6 - SHELL IGCC POWER PLANT WITH CO_2 CAPTURE

This case is configured to produce electric power with CO_2 capture. The plant configuration is the same as Case 5, namely two Shell gasifier trains, two advanced F class turbines, two HRSGs and one steam turbine. The gross power output is constrained by the capacity of the two combustion turbines, and since the CO_2 capture and compression process increases the auxiliary load on the plant, the net output is significantly reduced relative to Case 5 (517 MW versus 636 MW).

The process description for Case 6 is similar to Case 5 with several notable exceptions to accommodate CO_2 capture. A BFD and stream tables for Case 6 are shown in Exhibit 3-98 and Exhibit 3-99, respectively. Instead of repeating the entire process description, only differences from Case 5 are reported here.

Coal Preparation and Feed Systems

No differences from Case 5.

Gasification

The gasification process is the same as Case 5 with the following exceptions:

- The syngas exiting the gasifier (stream 12) is quenched to 399°C (750°F) with water rather than recycled syngas to provide a portion of the water required for water gas shift
- Total coal feed (as-received) to the two gasifiers is 5,151 tonnes/day (5,678 TPD) (stream 9)
- The ASU provides 4,070 tonnes/day (4,480 TPD) of 95 mole percent oxygen to the gasifier and Claus plant (streams 5 and 3)

Raw Gas Cooling/Particulate Removal

Following the water quench and particulate removal the syngas is cooled to 260°C (500°F) prior to the syngas scrubber (stream 13) by vaporizing HP BFW and pre-heating IP BFW.

Syngas Scrubber/Sour Water Stripper

Syngas exits the scrubber at 204°C (400°F).

Sour Gas Shift (SGS)

The SGS process was described in Section 3.1.3. In Case 6 the syngas after the scrubber is reheated to 285°C (545°F) and then steam (stream 14) is added to adjust the H_2O:CO molar ratio to approximately 2:1 prior to the first SGS reactor. The hot syngas exiting the first stage of SGS is used to generate the steam that is added in stream 14. One more stage of SGS (for a total of two) results in 95.6 percent overall conversion of the CO to CO_2. The warm syngas from the second stage of SGS is cooled to 241°C (465°F) by preheating the syngas prior to the first stage of SGS. The SGS catalylst also serves to hydrolyze COS thus eliminating the need for a separate COS hydrolysis reactor. Following the second stage of SGS, the syngas is further cooled to 35°C (95°F) prior to the mercury removal beds.

Mercury Removal and Acid Gas Removal

Mercury removal is the same as in Case 5

Exhibit 3-98 Case 6 Process Flow Diagram, Shell IGCC with CO_2 Capture

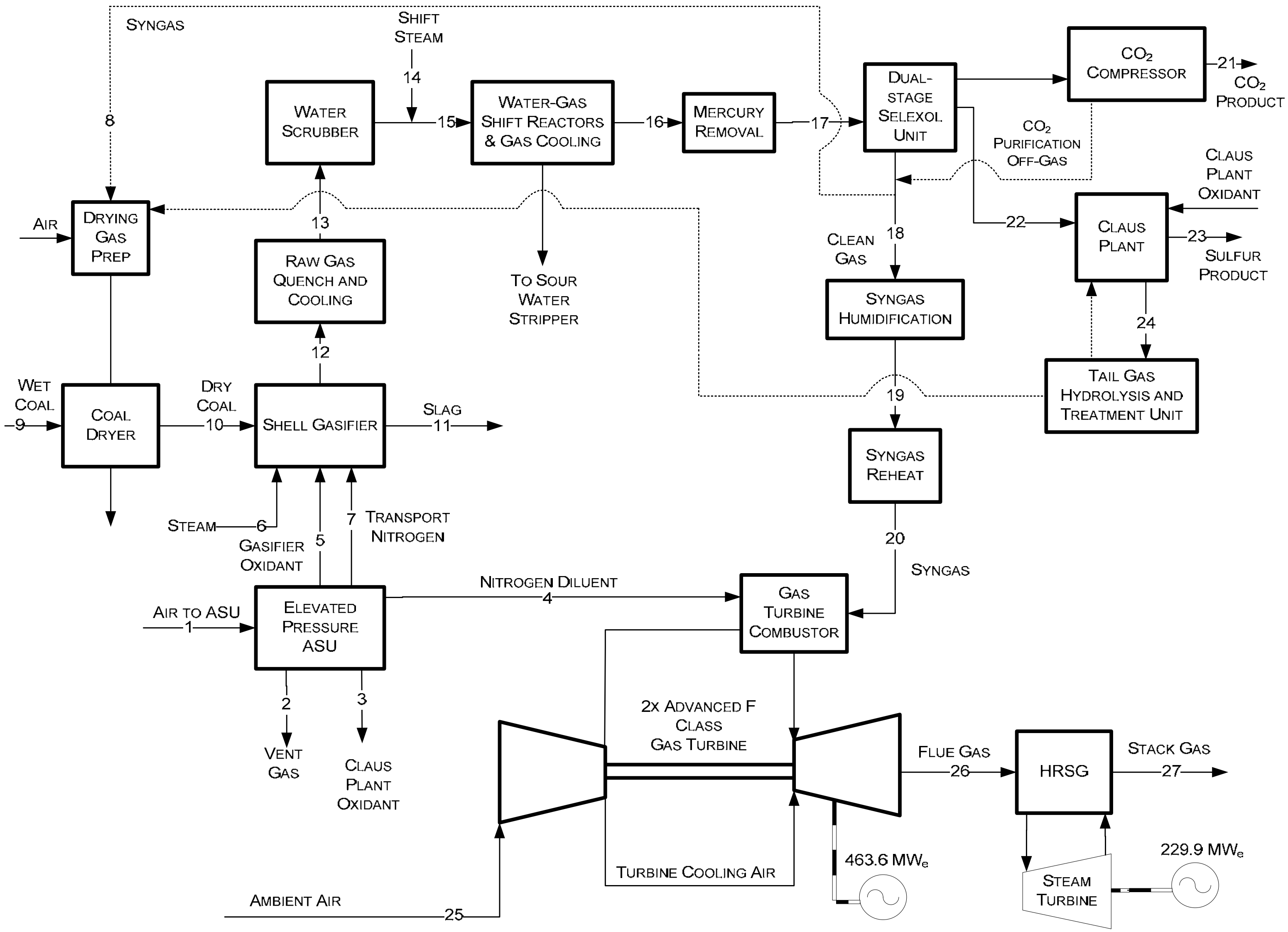

Exhibit 3-99 Case 6 Stream Table, Shell IGCC with CO_2 Capture

	1	2	3	4	5	6	7	8	9[A]	10[A]	11	12	13	14
V-L Mole Fraction														
Ar	0.0094	0.0263	0.0360	0.0024	0.0360	0.0000	0.0000	0.0102	0.0000	0.0000	0.0000	0.0097	0.0052	0.0000
CH_4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0004	0.0000	0.0000	0.0000	0.0004	0.0002	0.0000
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0265	0.0000	0.0000	0.0000	0.5716	0.3070	0.0000
CO_2	0.0003	0.0091	0.0000	0.0000	0.0000	0.0000	0.0000	0.0211	0.0000	0.0000	0.0000	0.0211	0.0113	0.0000
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0007	0.0004	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.8874	0.0000	0.0000	0.0000	0.2901	0.1558	0.0000
H_2O	0.0104	0.2820	0.0000	0.0004	0.0000	1.0000	0.0000	0.0001	1.0000	1.0000	0.0000	0.0364	0.4826	1.0000
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0081	0.0043	0.0000
N_2	0.7722	0.4591	0.0140	0.9918	0.0140	0.0000	1.0000	0.0543	0.0000	0.0000	0.0000	0.0585	0.0314	0.0000
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0033	0.0018	0.0000
O_2	0.2077	0.2235	0.9500	0.0054	0.9500	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	56,388	2,025	230	40,650	11,358	2,534	2,110	491	2,923	1,218	0	42,059	78,325	11,679
V-L Flowrate (lb/hr)	1,627,030	53,746	7,428	1,140,640	366,070	45,657	59,121	2,651	52,617	21,935	0	865,967	1,519,300	210,400
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	420,559	420,559	47,374	0	0	0
Temperature (°F)	238	70	90	385	518	750	560	121	59	215	2,595	2,595	500	750
Pressure (psia)	190.0	16.4	125.0	460.0	740.0	740.0	815.0	469.6	14.7	14.7	614.7	604.7	564.7	825.0
Enthalpy (BTU/lb)[B]	56.9	26.8	11.4	88.0	107.7	1409.5	132.2	113.8	---	---	---	1012.8	665.9	1,368.5
Density (lb/ft^3)	0.732	0.104	0.688	1.424	2.272	1.027	2.086	0.407	---	---	---	0.378	1.064	1.145
Molecular Weight	28.854	26.545	32.229	28.060	32.229	18.015	28.013	5.399	---	---	---	20.589	19.397	18.015

A - Solids flowrate includes dry coal; V-L flowrate includes water from coal

B - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 3-99 Case 6 Stream Table (Continued)

	15	16	17	18	19	20	21	22	23	24	25	26	27
V-L Mole Fraction													
Ar	0.0046	0.0064	0.0064	0.0102	0.0099	0.0099	0.0000	0.0000	0.0000	0.0074	0.0094	0.0091	0.0091
CH_4	0.0002	0.0002	0.0002	0.0004	0.0004	0.0004	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.2697	0.0166	0.0166	0.0265	0.0256	0.0256	0.0000	0.0000	0.0000	0.0792	0.0000	0.0000	0.0000
CO_2	0.0100	0.3771	0.3771	0.0211	0.0204	0.0204	1.0000	0.3526	0.0000	0.2293	0.0003	0.0063	0.0063
COS	0.0003	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0006	0.0000	0.0003	0.0000	0.0000	0.0000
H_2	0.1369	0.5547	0.5547	0.8874	0.8584	0.8584	0.0000	0.0000	0.0000	0.0417	0.0000	0.0000	0.0000
H_2O	0.5455	0.0014	0.0014	0.0001	0.0327	0.0327	0.0000	0.0502	0.0000	0.4003	0.0108	0.1258	0.1258
H_2S	0.0038	0.0050	0.0050	0.0000	0.0000	0.0000	0.0000	0.3122	0.0000	0.0013	0.0000	0.0000	0.0000
N_2	0.0276	0.0385	0.0385	0.0543	0.0526	0.0526	0.0000	0.2845	0.0000	0.2379	0.7719	0.7513	0.7513
NH_3	0.0016	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2076	0.1075	0.1075
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0026	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	89,158	63,376	63,376	39,127	40,448	40,448	22,707	1,017	0	1,603	244,799	308,019	308,019
V-L Flowrate (lb/hr)	1,714,460	1,249,470	1,249,470	211,226	235,031	235,031	999,309	35,657	0	42,962	7,062,330	8,438,000	8,438,000
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	11,825	0	0	0	0
Temperature (°F)	574	95	95	121	213	385	156	124	352	280	59	1,051	270
Pressure (psia)	544.7	482.6	472.6	469.6	453.9	448.9	2,214.7	60.0	23.6	23.6	14.7	15.2	15.2
Enthalpy (BTU/lb)[B]	767.7	25.6	25.6	113.8	327.0	535.7	-46.4	37.9	-100.6	362.5	13.8	364.1	150.8
Density (lb/ft^3)	0.944	1.598	1.565	0.407	0.365	0.288	30.929	0.343	329.618	0.080	0.076	0.026	0.053
Molecular Weight	19.229	19.715	19.715	5.399	5.811	5.811	44.010	35.063	256.528	26.798	28.849	27.394	27.394

B - Reference conditions are 32.02 F & 0.089 PSIA

The AGR process in Case 6 is a two stage Selexol process where H_2S is removed in the first stage and CO_2 in the second stage of absorption. The process results in three product streams, the clean syngas (stream 18), a CO_2-rich stream and an acid gas feed to the Claus plant (stream 22). The acid gas contains 31 percent H_2S and 35 percent CO_2 with the balance primarily N_2. The CO_2-rich stream is discussed further in the CO_2 compression section.

CO_2 Compression and Dehydration

CO_2 from the AGR process is generated at three pressure levels. The LP stream is compressed from 0.15 MPa (22 psia) to 1.1 MPa (160 psia) and then combined with the MP stream. The HP stream is combined between compressor stages at 2.1 MPa (300 psia). The combined stream is compressed from 2.1 MPa (300 psia) to a supercritical condition at 15.3 MPa (2215 psia) using a multiple-stage, intercooled compressor. During compression, the CO_2 stream is dehydrated to a dewpoint of -40ºC (-40°F) with triethylene glycol. The raw CO_2 stream from the Selexol process contains over 93 percent CO_2 with the balance primarily nitrogen. For modeling purposes it was assumed that the impurities were separated from the CO_2 and combined with the clean syngas stream from the Selexol process. The pure CO_2 (stream 21) is transported to the plant fence line and is sequestration ready. CO_2 TS&M costs were estimated using the methodology described in Section 2.7.

Claus Unit

The Claus plant is the same as Case 5 with the following exceptions:

- 5,364 kg/h (11,825 lb/h) of sulfur (stream 23) are produced
- The waste heat boiler generates 14,099 kg/h (31,082 lb/h) of 4.7 MPa (679 psia) steam, which provides all of the Claus plant process needs and provides some additional steam to the medium pressure steam header.

Power Block

Clean syngas from the AGR plant is combined with a small amount of clean gas from the CO_2 compression process (stream 18) and partially humidified because the nitrogen available from the ASU is insufficient to provide adequate dilution. The moisturized syngas is reheated to 196°C (385°F) using HP boiler feedwater, diluted with nitrogen (stream 4), and then enters the CT burner. The exhaust gas (stream 26) exits the CT at 566°C (1051°F) and enters the HRSG where additional heat is recovered. The flue gas exits the HRSG at 132°C (270°F) (stream 27) and is discharged through the plant stack. The steam raised in the HRSG is used to power an advanced commercially available steam turbine using a 12.4 MPa/538°C/538°C (1800 psig/1000°F/1000°F) steam cycle. There is no integration between the CT and the ASU in this case.

Air Separation Unit

The same elevated pressure ASU is used as in Case 5 and produces 4,070 tonnes/day (4,480 TPD) of 95 mole percent oxygen and 12,420 tonnes/day (13,690 TPD) of nitrogen. There is no integration between the ASU and the combustion turbine.

Balance of Plant

Balance of plant items were covered in Sections 3.1.9, 3.1.10 and 3.1.11.

3.4.9 CASE 6 PERFORMANCE RESULTS

The Case 6 modeling assumptions were presented previously in Section 3.4.3.

The plant produces a net output of 517 MWe at a net plant efficiency of 32.0 percent (HHV basis). Overall performance for the plant is summarized in Exhibit 3-100 which includes auxiliary power requirements. The ASU accounts for approximately 64 percent of the auxiliary load between the main air compressor, the nitrogen compressor, the oxygen compressor and ASU auxiliaries. The two-stage Selexol process and CO_2 compression account for an additional 25 percent of the auxiliary power load. The BFW and circulating water system (circulating water pumps and cooling tower fan) comprise about 5 percent of the load, leaving 6 percent of the auxiliary load for all other systems.

Exhibit 3-100 Case 6 Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine Power	463,630
Steam Turbine Power	229,925
TOTAL POWER, kWe	**693,555**
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	440
Coal Milling	2,210
Slag Handling	570
Air Separation Unit Auxiliaries	1,000
Air Separation Unit Main Air Compressor	62,970
Oxygen Compressor	10,540
Nitrogen Compressor	38,670
Syngas Recycle Compressor	0
Incinerator Air Blower	160
CO_2 Compressor	28,050
Boiler Feedwater Pumps	3,290
Condensate Pump	310
Flash Bottoms Pump	200
Circulating Water Pumps	3,440
Cooling Tower Fans	1,780
Scrubber Pumps	390
Double Stage Selexol Unit Auxiliaries	15,500
Gas Turbine Auxiliaries	1,000
Steam Turbine Auxiliaries	100
Claus Plant/TGTU Auxiliaries	250
Miscellaneous Balance of Plant (Note 1)	3,000
Transformer Loss	2,550
TOTAL AUXILIARIES, kWe	**176,420**
NET POWER, kWe	**517,135**
Net Plant Efficiency, % (HHV)	32.0
Net Plant Heat Rate (Btu/kWh)	10,674
CONDENSER COOLING DUTY 10^6 kJ/h (10^6 Btu/h)	**1,465 (1,390)**
CONSUMABLES	
As-Received Coal Feed, kg/h (lb/h)	214,629 (473,176)
Thermal Input, kWt	1,617,772
Raw Water Usage, m^3/min (gpm)	17.3 (4,563)

Note 1: Includes plant control systems, lighting, HVAC and miscellaneous low voltage loads

Environmental Performance

The environmental targets for emissions of Hg, NO_X, SO_2, CO_2 and particulate matter were presented in Section 2.4. A summary of the plant air emissions for Case 6 is presented in Exhibit 3-101.

Exhibit 3-101 Case 6 Air Emissions

	kg/GJ ($lb/10^6$ Btu)	Tonne/year (ton/year) 80% capacity factor	kg/MWh (lb/MWh)
SO_2	0.0045 (0.0105)	185 (204)	0.038 (0.084)
NO_X	0.021 (0.049)	856 (944)	0.176 (0.388)
Particulates	0.003 (0.0071)	125 (137)	0.026 (0.057)
Hg	$0.25x10^{-6}$ ($0.57x10^{-6}$)	0.010 (0.011)	$2.1x10^{-6}$ ($4.5x10^{-6}$)
CO_2	8.0 (18.7)	328,000 (361,000)	67.4 (149)
CO_2[1]			90.4 (199)

[1] CO_2 emissions based on net power instead of gross power

The low level of SO_2 emissions is achieved by capture of the sulfur in the gas by the two-stage Selexol AGR process. The CO_2 capture target results in the sulfur compounds being removed to a greater extent than required in the environmental targets of Section 2.4. The clean syngas exiting the AGR process has a sulfur concentration of approximately 22 ppmv. This results in a concentration in the flue gas of about 3 ppmv. The H_2S-rich regeneration gas from the AGR system is fed to a Claus plant, producing elemental sulfur. The tail gas treatment unit removes most of the sulfur from the Claus tail gas, which is recycled to the Claus unit inlet. The clean gas from the tail gas treatment unit is sent to the coal dryer prior to being vented to atmosphere.

NO_X emissions are limited by the use of nitrogen dilution and humidification to 15 ppmvd (as NO_2 @ 15 percent O_2). Ammonia in the syngas is removed with process condensate prior to the low-temperature AGR process and subsequently destroyed in the Claus plant burner. This helps lower NO_X levels as well.

Particulate discharge to the atmosphere is limited to extremely low values by the use of a cyclone and a barrier filter in addition to the syngas scrubber and the gas washing effect of the AGR absorber. The particulate emissions represent filterable particulate only.

Ninety five percent of mercury is captured from the syngas by an activated carbon bed. Ninety five percent of the CO_2 from the syngas is captured in the AGR system and compressed for sequestration. Because not all of the CO is converted to CO_2 in the shift reactors, the overall CO_2 removal is 90.2 percent.

The carbon balance for the plant is shown in Exhibit 3-102. The carbon input to the plant consists of carbon in the air in addition to carbon in the coal. Carbon in the air is not used in the carbon capture equation below, but it is not neglected in the balance since the Aspen model accounts for air components throughout. Carbon leaves the plant as unburned carbon in the slag, as dissolved CO_2 in the wastewater blowdown stream, and CO_2 in the stack gas, coal dryer vent gas, ASU vent gas and the captured CO_2 product. Carbon in the wastewater blowdown stream is calculated by difference to close the material balance. The carbon capture efficiency is defined as the amount of carbon in the CO_2 product stream relative to the amount of carbon in the coal less carbon contained in the slag, represented by the following fraction:

(Carbon in Product for Sequestration)/[(Carbon in the Coal)-(Carbon in Slag)] or
272,478/(301,649-1,511) *100 or
90.8 percent

Exhibit 3-102 Case 6 Carbon Balance

Carbon In, kg/hr (lb/hr)		Carbon Out, kg/hr (lb/hr)	
Coal	136,826 (301,649)	**Slag**	685 (1,511)
Air (CO_2)	500 (1,102)	**Stack Gas**	10,610 (23,390)
		CO_2 Product	123,595 (272,478)
		ASU Vent	101 (222)
		Coal Dryer	2,137 (4,712)
		Wastewater	198 (438)
Total	137,326 (302,751)	**Total**	137,326 (302,751)

Exhibit 3-103 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered in the Claus plant, dissolved SO_2 in the wastewater blowdown stream, sulfur emitted in the stack gas and sulfur from the tail gas unit that is vented through the coal dryer. Sulfur in the slag is considered negligible, and the sulfur content of the blowdown stream is calculated by difference to close the material balance. The total sulfur capture is represented by the following fraction:

(Sulfur byproduct/Sulfur in the coal) or
(11,825/11,877) or
99.6 percent

Exhibit 3-103 Case 6 Sulfur Balance

Sulfur In, kg/hr (lb/hr)		Sulfur Out, kg/hr (lb/hr)	
Coal	5,387 (11,877)	**Elemental Sulfur**	5,364 (11,825)
		Stack Gas	12 (27)
		Dryer Gas	1 (2)
		Wastewater	10 (23)
Total	5,387 (11,877)	**Total**	5,387 (11,877)

Exhibit 3-104 shows the overall water balance for the plant. Raw water is obtained from groundwater (50 percent) and from municipal sources (50 percent). Water demand represents the total amount of water required for a particular process. Some water is recovered within the process, primarily as syngas condensate, and that water is re-used as internal recycle. Raw water makeup is the difference between water demand and internal recycle.

Exhibit 3-104 Case 6 Water Balance

Water Use	Water Demand, m^3/min (gpm)	Internal Recycle, m^3/min (gpm)	Raw Water Makeup, m^3/min (gpm)
Gasifier Steam	0.3 (91)	0	0.3 (91)
Shift Steam	1.6 (420)	0	1.6 (420)
Humidifier	0.3 (67)	0.3 (67)	0
Slag Handling	0.4 (123)	0.4 (123)	0
Quench/Scrubber	4.9 (1,306)	2.6 (693)	2.3 (612)
BFW Makeup	0.2 (45)	0	0.2 (45)
Cooling Tower Makeup	13.4 (3,528)	0.5 (133)	12.9 (3,395)
Total	**21.1 (5,581)**	**3.8 (1,017)**	**17.3 (4,564)**

Heat and Mass Balance Diagrams

Heat and mass balance diagrams are shown for the following subsystems in Exhibit 3-105 through Exhibit 3-109:

- Coal gasification and air separation unit
- Syngas cleanup
- Sulfur recovery and tail gas recycle
- Combined cycle power generation
- Steam and feedwater

An overall plant energy balance is provided in tabular form in Exhibit 3-110. The power out is the combined combustion turbine and steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 3-100) is calculated by multiplying the power out by a combined generator efficiency of 98.4 percent.

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Exhibit 3-105 Case 6 Coal Gasification and Air Separation Unit Heat and Mass Balance Schematic

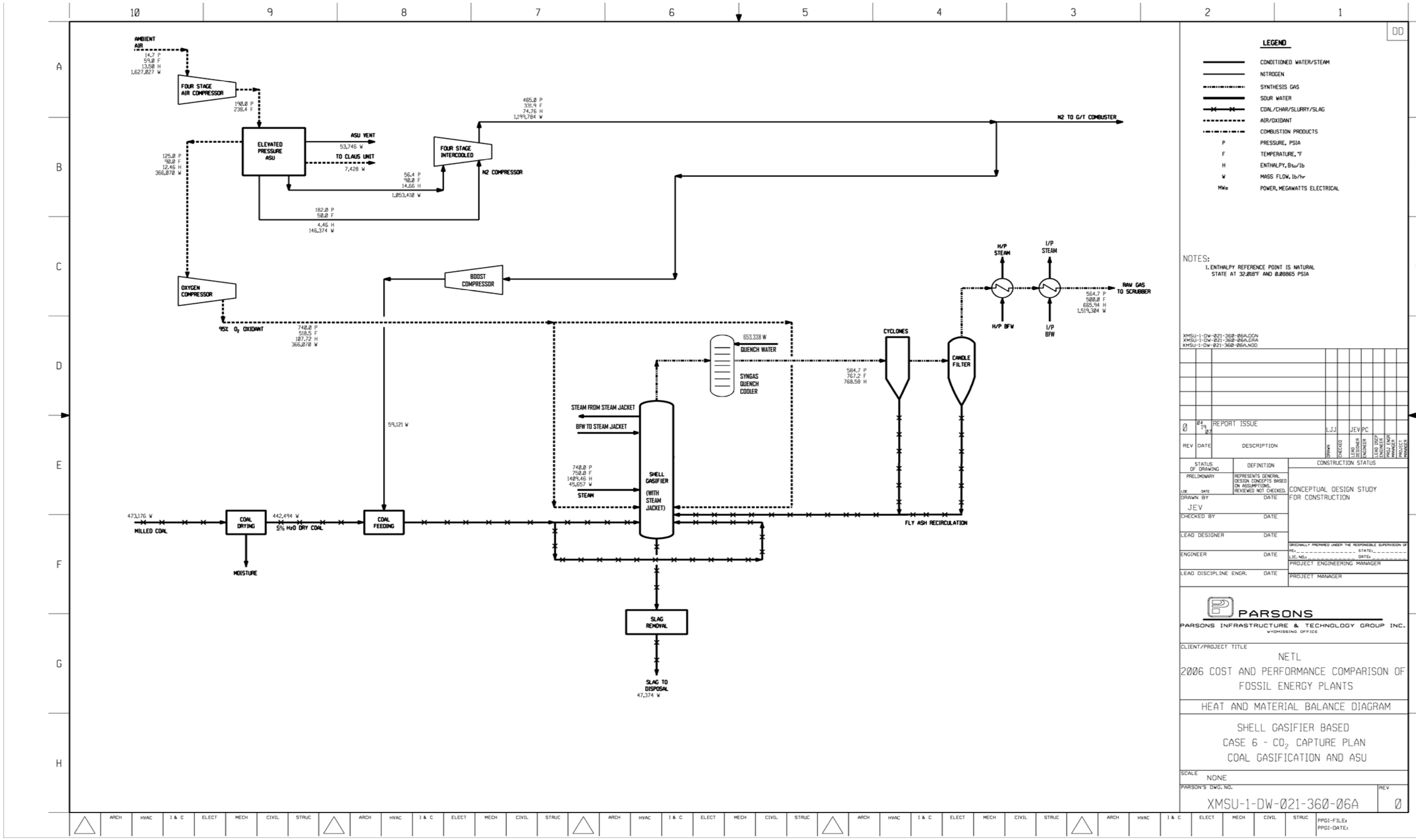

Exhibit 3-106 Case 6 Syngas Cleanup Heat and Mass Balance Schematic

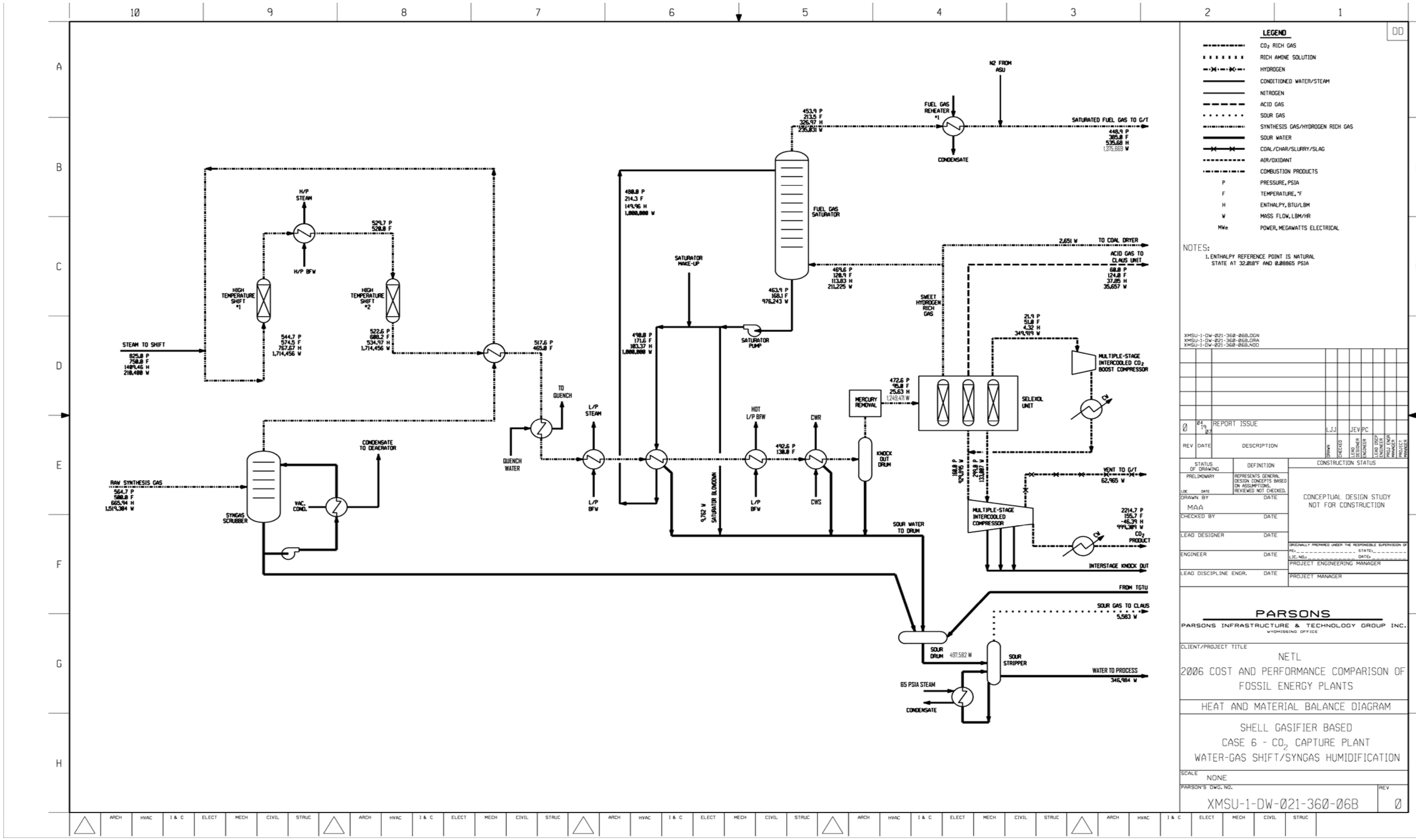

Exhibit 3-107 Case 6 Sulfur Recovery and Tail Gas Recycle Heat and Mass Balance Schematic

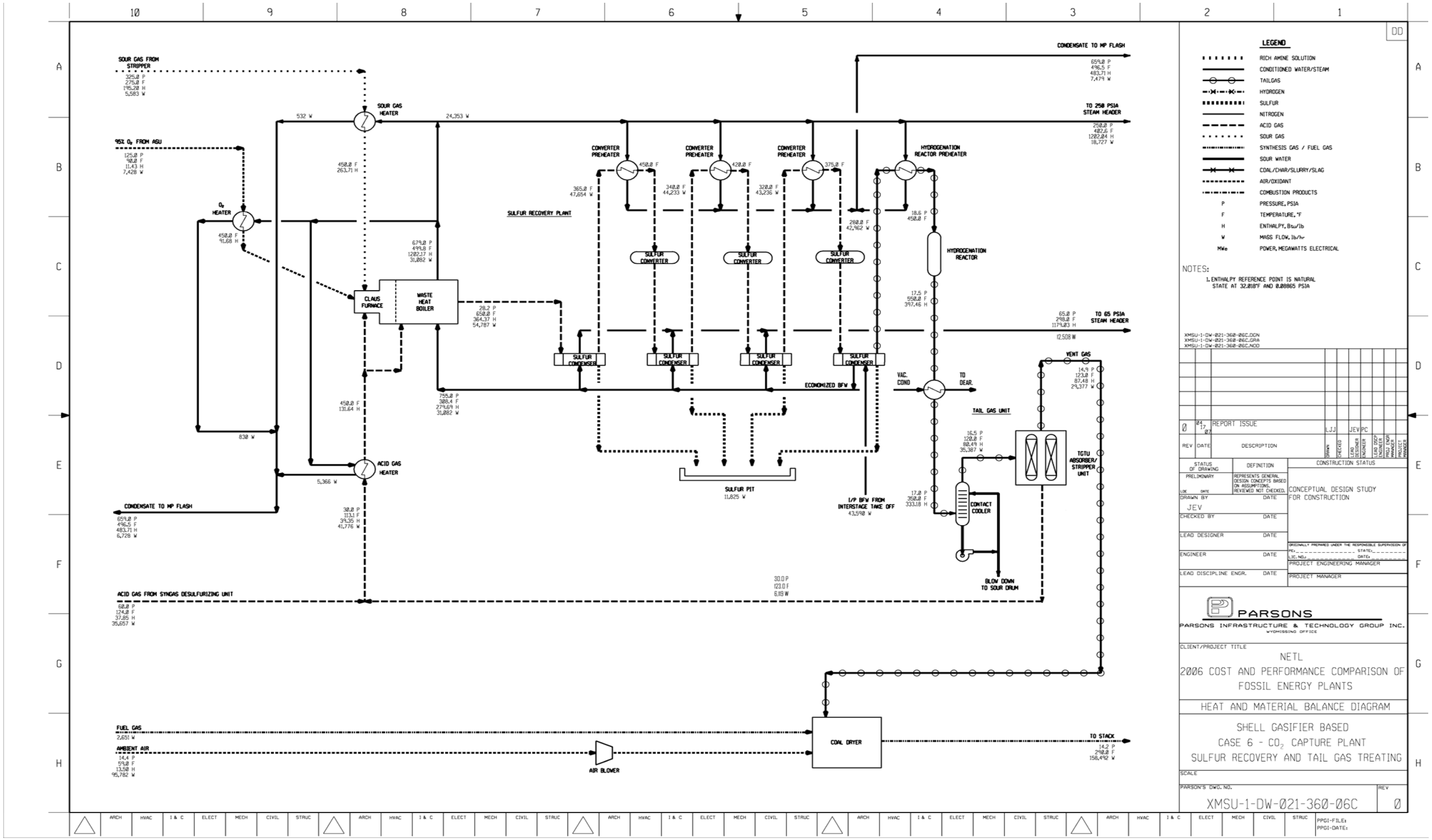

Exhibit 3-108 Case 6 Combined Cycle Power Generation Heat and Mass Balance Schematic

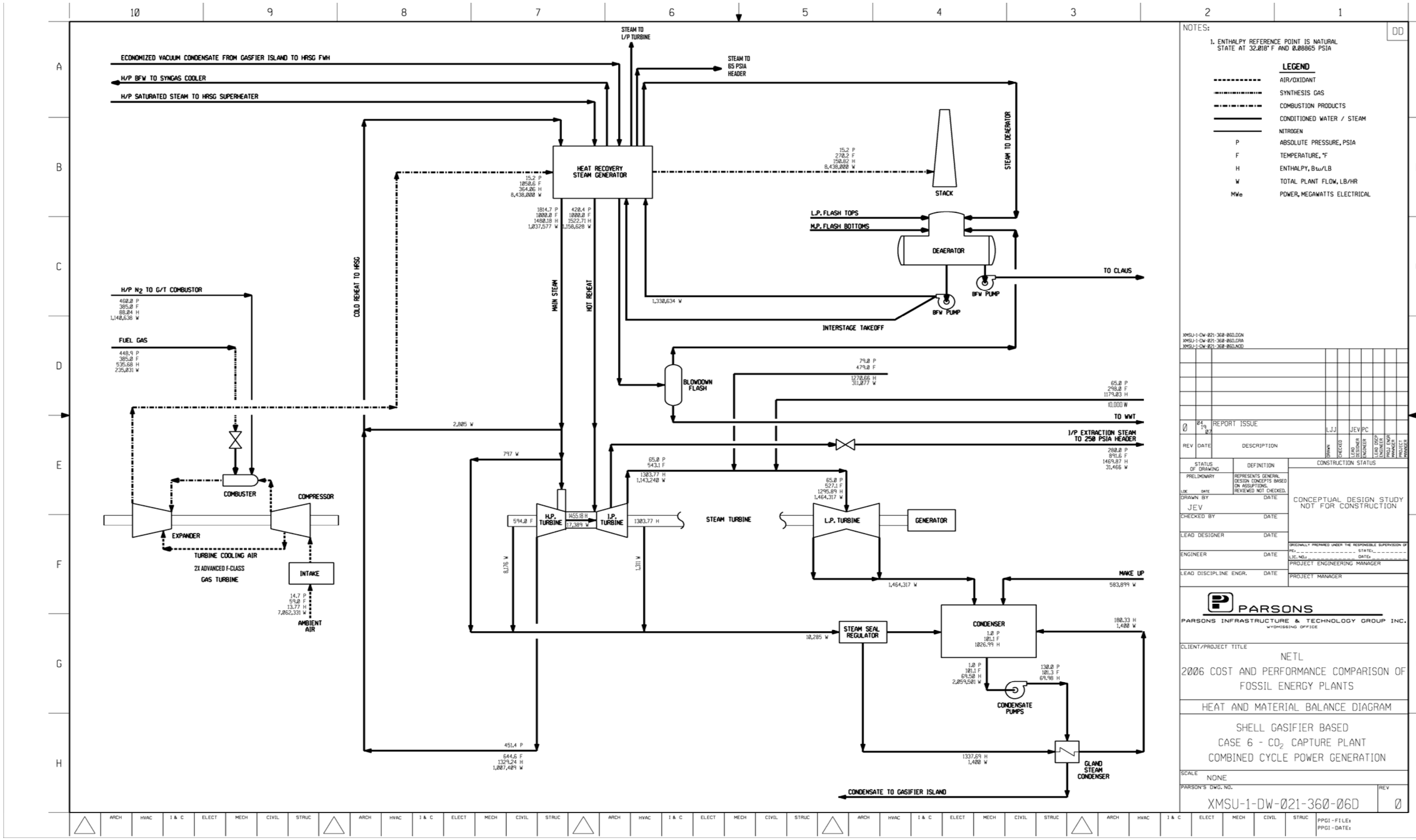

Exhibit 3-109 Case 6 Steam and Feedwater Heat and Mass Balance Schematic

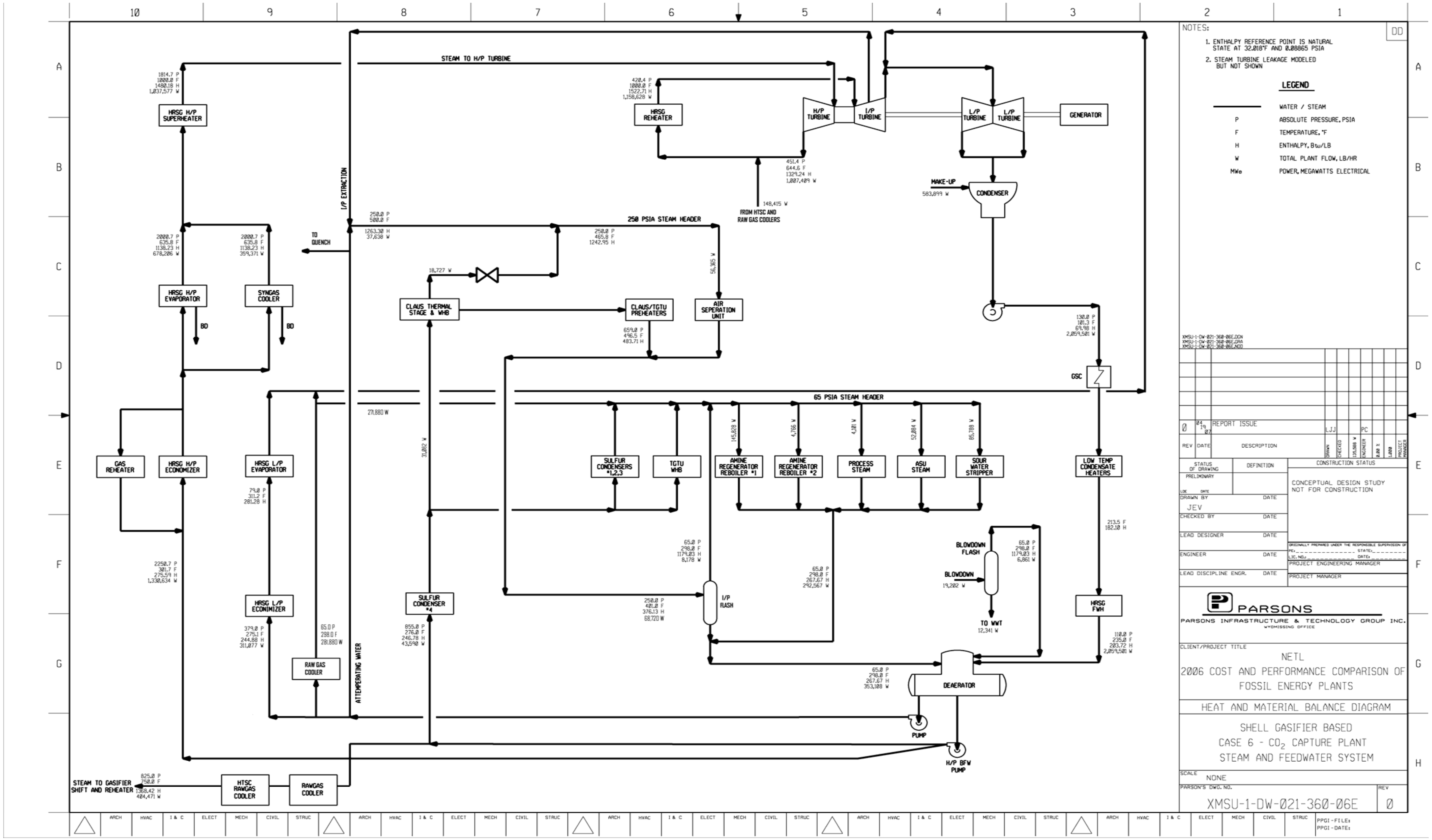

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Exhibit 3-110 Case 6 Overall Energy Balance (0°C [32°F] Reference)

	HHV	Sensible + Latent	Power	Total
Heat In (MMBtu/hr)				
Coal	5,520.2	4.6		5,524.8
ASU Air		22.0		22.0
CT Air		97.2		97.2
Incinerator Air		1.3		1.3
Water		23.2		23.2
Auxiliary Power			602.0	602.0
Totals	**5,520.2**	**148.4**	**602.0**	**6,270.5**
Heat Out (MMBtu/hr)				
ASU Intercoolers		222.8		222.8
ASU Vent		1.4		1.4
Slag	21.3	33.9		55.2
Sulfur	47.1	(1.2)		45.9
Dryer Stack Gas		59.5		59.5
CO_2 Compressor Intercoolers		115.4		115.4
CO_2 Product		(46.4)		(46.4)
HRSG Flue Gas		1,273.3		1,273.3
Condenser		1,390.0		1,390.0
Process Losses		748.8		748.8
Power			2,404.6	2,404.6
Totals	**68.4**	**3,797.5**	**2,404.6**	**6,270.5**

(1) Process Losses are calculated by difference and reflect various gasification, turbine, HRSG and other heat and work losses. Aspen flowsheet balance is within 0.5 percent.

3.4.10 CASE 6 - MAJOR EQUIPMENT LIST

Major equipment items for the Shell gasifier with CO_2 capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 3.4.11. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

ACCOUNT 1 COAL HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	181 tonne (200 ton)	2	0
2	Feeder	Belt	572 tonne/h (630 tph)	2	0
3	Conveyor No. 1	Belt	1,134 tonne/h (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,134 tonne/h (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,134 tonne/h (1,250 tph)	1	0
8	Reclaim Hopper	N/A	45 tonne (50 ton)	2	1
9	Feeder	Vibratory	181 tonne/h (200 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	354 tonne/h (390 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	181 tonne (200 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3" x 0 - 1-1/4" x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	354 tonne/h (390 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	354 tonne/h (390 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	816 tonne (900 ton)	3	0

ACCOUNT 2 COAL PREPARATION AND FEED

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Feeder	Vibratory	82 tonne/h (90 tph)	3	0
2	Conveyor No. 6	Belt w/tripper	236 tonne/h (260 tph)	1	0
3	Roller Mill Feed Hopper	Dual Outlet	472 tonne (520 ton)	1	0
4	Weigh Feeder	Belt	118 tonne/h (130 tph)	2	0
5	Coal Drying and Pulverization	Rotary	118 tonne/h (130 tph)	2	0

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	927,433 liters (245,000 gal)	3	0
2	Condensate Pumps	Vertical canned	8,631 lpm @ 91 m H2O (2,280 gpm @ 300 ft H2O)	2	1
3	Deaerator (integral w/ HRSG)	Horizontal spray type	603,732 kg/h (1,331,000 lb/h)	2	0
4	Intermediate Pressure Feedwater Pump	Horizontal centrifugal, single stage	3,975 lpm @ 283 m H2O (1,050 gpm @ 930 ft H2O)	2	1
5	High Pressure Feedwater Pump No. 1	Barrel type, multi-stage, centrifugal	HP water: 4,580 lpm @ 1,890 m H2O (1,210 gpm @ 6,200 ft H2O)	2	1
6	High Pressure Feedwater Pump No. 2	Barrel type, multi-stage, centrifugal	IP water: 1,173 lpm @ 223 m H2O (310 gpm @ 730 ft H2O)	2	1
7	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/h, 2.8 MPa, 343°C (40,000 lb/h, 400 psig, 650°F)	1	0
8	Service Air Compressors	Flooded Screw	28 m3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
9	Instrument Air Dryers	Duplex, regenerative	28 m3/min (1,000 scfm)	2	1
10	Closed Cylce Cooling Heat Exchangers	Plate and frame	58 MMkJ/h (55 MMBtu/h) each	2	0
11	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,820 lpm @ 21 m H2O (5,500 gpm @ 70 ft H2O)	2	1
12	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 107 m H2O (1,000 gpm @ 350 ft H2O)	1	1
13	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 76 m H2O (700 gpm @ 250 ft H2O)	1	1
14	Raw Water Pumps	Stainless steel, single suction	9,577 lpm @ 18 m H2O (2,530 gpm @ 60 ft H2O)	2	1
15	Filtered Water Pumps	Stainless steel, single suction	4,353 lpm @ 49 m H2O (1,150 gpm @ 160 ft H2O)	2	1
16	Filtered Water Tank	Vertical, cylindrical	1,048,567 liter (277,000 gal)	2	0
17	Makeup Water Demineralizer	Anion, cation, and mixed bed	1,060 lpm (280 gpm)	2	0
18	Liquid Waste Treatment System		10 years, 24-hour storm	1	0

ACCOUNT 4 GASIFIER, ASU AND ACCESSORIES INCLUDING LOW TEMPERATURE HEAT RECOVERY AND FUEL GAS SATURATION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gasifier	Pressurized dry-feed, entrained bed	2,812 tonne/day, 4.2 MPa (3,100 tpd, 615 psia)	2	0
2	Synthesis Gas Cooler	Convective spiral-wound tube boiler	379,204 kg/h (836,000 lb/h)	2	0
3	Synthesis Gas Cyclone	High efficiency	375,121 kg/h (827,000 lb/h) Design efficiency 90%	2	0
4	Candle Filter	Pressurized filter with pulse-jet cleaning	metallic filters	2	0
5	Syngas Scrubber Including Sour Water Stripper	Vertical upflow	375,121 kg/h (827,000 lb/h)	2	0
6	Raw Gas Coolers	Shell and tube with condensate drain	713,048 kg/h (1,572,000 lb/h)	6	0
7	Raw Gas Knockout Drum	Vertical with mist eliminator	312,072 kg/h, 35°C, 3.4 MPa (688,000 lb/h, 95°F, 488 psia)	2	0
8	Saturation Water Economizers	Shell and tube	427,738 kg/h (943,000 lb/h)	2	0
9	Fuel Gas Saturator	Vertical tray tower	58,513 kg/h, 101°C, 3.2 MPa (129,000 lb/h, 213°F, 470 psia)	2	0
10	Saturator Water Pump	Centrifugal	4,164 lpm @ 21 m H2O (1,100 gpm @ 70 ft H2O)	2	2
11	Synthesis Gas Reheater	Shell and tube	58,513 kg/h (129,000 lb/h)	2	0
12	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	375,121 kg/h (827,000 lb/h) syngas	2	0
13	ASU Main Air Compressor	Centrifugal, multi-stage	5,550 m3/min @ 1.3 MPa (196,000 scfm @ 190 psia)	2	0
14	Cold Box	Vendor design	2,268 tonne/day (2,500 tpd) of 95% purity oxygen	2	0
15	Oxygen Compressor	Centrifugal, multi-stage	1,133 m3/min @ 5.1 MPa (40,000 scfm @ 740 psia)	2	0
16	Nitrogen Compressor	Centrifugal, multi-stage	3,710 m3/min @ 3.4 MPa (131,000 scfm @ 490 psia)	2	0
17	Nitrogen Boost Compressor	Centrifugal, multi-stage	510 m3/min @ 2.3 MPa (18,000 scfm @ 340 psia)	2	0

ACCOUNT 5 SYNGAS CLEANUP

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Mercury Adsorber	Sulfated carbon bed	311,618 kg/h (687,000 lb/h) 35°C (95°F) 3.3 MPa (483 psia)	2	0
2	Sulfur Plant	Claus type	142 tonne/day (156 tpd)	1	0
3	Water Gas Shift Reactors	Fixed bed, catalytic	427,738 kg/h (943,000 lb/h) 302°C (575°F) 3.8 MPa (545 psia)	4	0
4	Shift Reactor Heat Recovery Exhchangers	Shell and Tube	Exchanger 1: 211 MMkJ/h (200 MMBtu/h) Exchanger 2: 63 MMkJ/h (60 MMBtu/h)	4	0
5	Acid Gas Removal Plant	Two-stage Selexol	311,618 kg/h (687,000 lb/h) 51°C (124°F) 3.3 MPa (473 psia)	2	0
6	Tail Gas Treatment Unit	Proprietary amine, absorber/stripper	17,645 kg/h (38,900 lb/h) 49°C (120°F) 0.1 MPa (16.4 psia)	1	0
7	Tail Gas Treatment Incinerator	N/A	67 MMkJ/h (64 MMBtu/h)	1	0

ACCOUNT 5B CO_2 COMPRESSION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CO2 Compression	Integrally geared, multi-stage centrifugal	1,119 m3/min @ 15.3 MPa (39,500 scfm @ 2,215 psia)	4	1

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gas Turbine	Advanced F class	232 MW	2	0
2	Gas Turbine Generator	TEWAC	260 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	2	0

ACCOUNT 7 HRSG, DUCTING, AND STACK

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	CS plate, type 409SS liner	76 m (250 ft) high x 8.5 m (28 ft) diameter	1	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	Main steam - 258,851 kg/h, 12.4 MPa/538°C (570,667 lb/h, 1,800 psig/1,000°F) Reheat steam - 289,050 kg/h, 2.9 MPa/538°C (637,245 lb/h, 420 psig/1,000°F)	2	0

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	242 MW 12.4 MPa/538°C/538°C (1800 psig/ 1000°F/1000°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitiation	270 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Steam Bypass	One per HRSG	50% steam flow @ design steam conditions	2	0
4	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,613 MMkJ/h (1,530 MMBtu/h), Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1	0

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	344,475 lpm @ 30 m (91,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT / 1,919 MMkJ/h (1,820 MMBtu/h) heat duty	1	0

ACCOUNT 10 SLAG RECOVERY AND HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Slag Quench Tank	Water bath	227,126 liters (60,000 gal)	2	0
2	Slag Crusher	Roll	12 tonne/h (13 tph)	2	0
3	Slag Depressurizer	Lock Hopper	12 tonne/h (13 tph)	2	0
4	Slag Receiving Tank	Horizontal, weir	147,632 liters (39,000 gal)	2	0
5	Black Water Overflow Tank	Shop fabricated	68,138 liters (18,000 gal)	2	
6	Slag Conveyor	Drag chain	12 tonne/h (13 tph)	2	0
7	Slag Separation Screen	Vibrating	12 tonne/h (13 tph)	2	0
8	Coarse Slag Conveyor	Belt/bucket	12 tonne/h (13 tph)	2	0
9	Fine Ash Settling Tank	Vertical, gravity	219,556 liters (58,000 gal)	2	0
10	Fine Ash Recycle Pumps	Horizontal centrifugal	38 lpm @ 14 m H2O (10 gpm @ 46 ft H2O)	2	2
11	Grey Water Storage Tank	Field erected	71,923 liters (19,000 gal)	2	0
12	Grey Water Pumps	Centrifugal	265 lpm @ 433 m H2O (70 gpm @ 1,420 ft H2O)	2	2
13	Slag Storage Bin	Vertical, field erected	816 tonne (900 tons)	2	0
14	Unloading Equipment	Telescoping chute	100 tonne/h (110 tph)	1	0

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	24 kV/345 kV, 260 MVA, 3-ph, 60 Hz	2	0
2	STG Transformer	Oil-filled	24 kV/345 kV, 70 MVA, 3-ph, 60 Hz	1	0
3	Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 193 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 29 MVA, 3-ph, 60 Hz	1	1
5	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	2	0
6	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
7	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
8	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
9	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

ACCOUNT 12 INSTRUMENTATION AND CONTROLS

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

3.4.11 CASE 6 - COST ESTIMATING

The cost estimating methodology was described previously in Section 2.6. Exhibit 3-111 shows the total plant capital cost summary organized by cost account and Exhibit 3-112 shows a more detailed breakdown of the capital costs. Exhibit 3-113 shows the initial and annual O&M costs.

The estimated TPC of the Shell gasifier with CO_2 capture is $2,668/kW. The gasifier in Case 6 is slightly larger than Case 5, but the syngas cooler is much smaller in Case 6 (because of the quench configuration), which results in a lower overall cost for the Gasifier Account in Case 6. Process contingency represents 3.8 percent of the TPC and project contingency represents 14.0 percent. The 20-year LCOE, including CO_2 TS&M costs of 4.1 mills/kWh, is 110.4 mills/kWh.

Exhibit 3-111 Case 6 Total Plant Cost Summary

	Client:	USDOE/NETL								**Report Date:**	05-Apr-07		
	Project:	Bituminous Baseline Study											
					TOTAL PLANT COST SUMMARY								
	Case:	Case 06 - Shell IGCC w/ CO2											
	Plant Size:	517.1 MW,net		**Estimate Type:**		Conceptual				**Cost Base (Dec)**	2006	($x1000)	
Acct No.	**Item/Description**	**Equipment Cost**	**Material Cost**	**Labor Direct**	**Labor Indirect**	**Sales Tax**	**Bare Erected Cost $**	**Eng'g CM H.O.& Fee**	**Contingencies Process**	**Contingencies Project**	**TOTAL PLANT COST $**	**TOTAL PLANT COST $/kW**	
1	COAL & SORBENT HANDLING	$13,222	$2,465	$10,360	$0	$0	**$26,046**	$2,360	$0	$5,681	**$34,087**	$66	
2	COAL & SORBENT PREP & FEED	$104,780	$8,348	$17,611	$0	$0	**$130,739**	$11,350	$0	$28,418	**$170,507**	$330	
3	FEEDWATER & MISC. BOP SYSTEMS	$8,804	$7,082	$8,709	$0	$0	**$24,596**	$2,304	$0	$6,179	**$33,079**	$64	
4	GASIFIER & ACCESSORIES												
4.1	Gasifier, Syngas Cooler & Auxiliaries	$102,271	$0	$44,114	$0	$0	**$146,384**	$13,107	$20,012	$27,635	**$207,139**	$401	
4.2	Syngas Cooling (w/4.1)	w/4.1	$0	w/4.1	$0	$0	**$0**	$0	$0	$0	**$0**	$0	
4.3	ASU/Oxidant Compression	$144,337	$0	w/equip.	$0	$0	**$144,337**	$13,738	$0	$15,808	**$173,883**	$336	
4.4-4.9	Other Gasification Equipment	$25,903	$9,641	$15,020	$0	$0	**$50,564**	$4,796	$0	$11,764	**$67,123**	$130	
	SUBTOTAL 4	**$272,511**	**$9,641**	**$59,134**	**$0**	**$0**	**$341,285**	**$31,641**	**$20,012**	**$55,207**	**$448,145**	**$867**	
5A	Gas Cleanup & Piping	$80,918	$4,433	$69,321	$0	$0	**$154,672**	$14,826	$22,300	$38,565	**$230,362**	$445	
5B	CO_2 REMOVAL & COMPRESSION	$17,265	$0	$10,209	$0	$0	**$27,475**	$2,626	$0	$6,020	**$36,121**	$70	
6	COMBUSTION TURBINE/ACCESSORIES												
6.1	Combustion Turbine Generator	$88,000	$0	$5,325	$0	$0	**$93,325**	$8,779	$9,332	$11,144	**$122,580**	$237	
6.2-6.9	Combustion Turbine Other	$0	$684	$762	$0	$0	**$1,446**	$135	$0	$474	**$2,055**	$4	
	SUBTOTAL 6	**$88,000**	**$684**	**$6,087**	**$0**	**$0**	**$94,771**	**$8,914**	**$9,332**	**$11,618**	**$124,635**	**$241**	
7	HRSG, DUCTING & STACK												
7.1	Heat Recovery Steam Generator	$32,181	$0	$4,579	$0	$0	**$36,760**	$3,470	$0	$4,023	**$44,253**	$86	
7.2-7.9	Ductwork and Stack	$3,222	$2,268	$3,041	$0	$0	**$8,531**	$788	$0	$1,516	**$10,835**	$21	
	SUBTOTAL 7	**$35,402**	**$2,268**	**$7,620**	**$0**	**$0**	**$45,291**	**$4,258**	**$0**	**$5,539**	**$55,087**	**$107**	
8	STEAM TURBINE GENERATOR												
8.1	Steam TG & Accessories	$24,587	$0	$4,106	$0	$0	**$28,693**	$2,750	$0	$3,144	**$34,587**	$67	
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$8,905	$828	$6,089	$0	$0	**$15,822**	$1,435	$0	$3,347	**$20,604**	$40	
	SUBTOTAL 8	**$33,492**	**$828**	**$10,195**	**$0**	**$0**	**$44,515**	**$4,184**	**$0**	**$6,491**	**$55,191**	**$107**	
9	COOLING WATER SYSTEM	$6,933	$7,764	$6,432	$0	$0	**$21,129**	$1,940	$0	$4,752	**$27,821**	$54	
10	ASH/SPENT SORBENT HANDLING SYS	$17,865	$1,375	$8,869	$0	$0	**$28,109**	$2,676	$0	$3,363	**$34,149**	$66	
11	ACCESSORY ELECTRIC PLANT	$22,955	$8,041	$22,625	$0	$0	**$53,621**	$4,967	$0	$11,178	**$69,766**	$135	
12	INSTRUMENTATION & CONTROL	$10,193	$1,908	$6,843	$0	$0	**$18,945**	$1,746	$947	$3,620	**$25,258**	$49	
13	IMPROVEMENTS TO SITE	$3,207	$1,890	$7,973	$0	$0	**$13,070**	$1,284	$0	$4,306	**$18,660**	$36	
14	BUILDINGS & STRUCTURES	$0	$6,095	$7,021	$0	$0	**$13,117**	$1,192	$0	$2,349	**$16,657**	$32	
	TOTAL COST	**$715,547**	**$62,824**	**$259,009**	**$0**	**$0**	**$1,037,381**	**$96,266**	**$52,591**	**$193,286**	**$1,379,524**	**$2,668**	

Exhibit 3-112 Case 6 Total Plant Cost Details

Client:	USDOE/NETL	**Report Date:**	05-Apr-07
Project:	Bituminous Baseline Study		
	TOTAL PLANT COST SUMMARY		
Case:	Case 06 - Shell IGCC w/ CO2		
Plant Size:	517.1 MW,net **Estimate Type:** Conceptual	**Cost Base (Dec)**	2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	$3,472	$0	$1,714	$0	$0	$5,186	$464	$0	$1,130	$6,781	$13
1.2	Coal Stackout & Reclaim	$4,487	$0	$1,099	$0	$0	$5,586	$490	$0	$1,215	$7,291	$14
1.3	Coal Conveyors	$4,171	$0	$1,087	$0	$0	$5,259	$462	$0	$1,144	$6,865	$13
1.4	Other Coal Handling	$1,091	$0	$252	$0	$0	$1,343	$118	$0	$292	$1,753	$3
1.5	Sorbent Receive & Unload	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.6	Sorbent Stackout & Reclaim	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.7	Sorbent Conveyors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.8	Other Sorbent Handling	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.9	Coal & Sorbent Hnd.Foundations	$0	$2,465	$6,207	$0	$0	$8,672	$826	$0	$1,900	$11,399	$22
	SUBTOTAL 1.	**$13,222**	**$2,465**	**$10,360**	**$0**	**$0**	**$26,046**	**$2,360**	**$0**	**$5,681**	**$34,087**	**$66**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	$39,807	$2,378	$5,861	$0	$0	$48,046	$4,152	$0	$10,440	$62,638	$121
2.2	Prepared Coal Storage & Feed	$1,885	$449	$299	$0	$0	$2,633	$226	$0	$572	$3,430	$7
2.3	Dry Coal Injection System	$62,051	$727	$5,823	$0	$0	$68,601	$5,917	$0	$14,904	$89,421	$173
2.4	Misc.Coal Prep & Feed	$1,037	$750	$2,286	$0	$0	$4,073	$373	$0	$889	$5,336	$10
2.5	Sorbent Prep Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.6	Sorbent Storage & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.7	Sorbent Injection System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.8	Booster Air Supply System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.9	Coal & Sorbent Feed Foundation	$0	$4,043	$3,343	$0	$0	$7,386	$681	$0	$1,614	$9,681	$19
	SUBTOTAL 2.	**$104,780**	**$8,348**	**$17,611**	**$0**	**$0**	**$130,739**	**$11,350**	**$0**	**$28,418**	**$170,507**	**$330**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	$2,575	$4,477	$2,365	$0	$0	$9,417	$869	$0	$2,057	$12,344	$24
3.2	Water Makeup & Pretreating	$575	$60	$321	$0	$0	$955	$90	$0	$314	$1,359	$3
3.3	Other Feedwater Subsystems	$1,422	$482	$434	$0	$0	$2,338	$209	$0	$509	$3,057	$6
3.4	Service Water Systems	$331	$676	$2,347	$0	$0	$3,354	$324	$0	$1,104	$4,782	$9
3.5	Other Boiler Plant Systems	$1,779	$682	$1,693	$0	$0	$4,154	$389	$0	$909	$5,452	$11
3.6	FO Supply Sys & Nat Gas	$300	$567	$529	$0	$0	$1,397	$134	$0	$306	$1,837	$4
3.7	Waste Treatment Equipment	$798	$0	$489	$0	$0	$1,288	$125	$0	$424	$1,836	$4
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	$1,024	$138	$530	$0	$0	$1,692	$163	$0	$557	$2,412	$5
	SUBTOTAL 3.	**$8,804**	**$7,082**	**$8,709**	**$0**	**$0**	**$24,596**	**$2,304**	**$0**	**$6,179**	**$33,079**	**$64**
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries	$102,271	$0	$44,114	$0	$0	$146,384	$13,107	$20,012	$27,635	$207,139	$401
4.2	Syngas Cooling (w/4.1)	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.3	ASU/Oxidant Compression	$144,337	$0	w/equip.	$0	$0	$144,337	$13,738	$0	$15,808	$173,883	$336
4.4	LT Heat Recovery & FG Saturation	$25,903	$0	$9,746	$0	$0	$35,649	$3,426	$0	$7,815	$46,890	$91
4.5	Misc. Gasification Equipment w/4.1 & 4.2	w/4.1&4.2	$0	w/4.1&4.2	$0	$0	$0	$0	$0	$0	$0	$0
4.6	Other Gasification Equipment	$0	$1,589	$647	$0	$0	$2,236	$213	$0	$490	$2,938	$6
4.8	Major Component Rigging	w/4.1&4.2	$0	w/4.1&4.2	$0	$0	$0	$0	$0	$0	$0	$0
4.9	Gasification Foundations	$0	$8,052	$4,627	$0	$0	$12,679	$1,157	$0	$3,459	$17,295	$33
	SUBTOTAL 4.	**$272,511**	**$9,641**	**$59,134**	**$0**	**$0**	**$341,285**	**$31,641**	**$20,012**	**$55,207**	**$448,145**	**$867**

Exhibit 3-112 Case 6 Total Plant Cost Details (Continued)

	Client:	USDOE/NETL								Report Date:	05-Apr-07	
	Project:	Bituminous Baseline Study										
		TOTAL PLANT COST SUMMARY										
	Case:	Case 06 - Shell IGCC w/ CO2										
	Plant Size:	517.1 MW,net		Estimate Type:		Conceptual			Cost Base (Dec)	2006	($x1000)	

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5A	GAS CLEANUP & PIPING											
5A.1	Double Stage Selexol	$59,698	$0	$51,207	$0	$0	$110,905	$10,647	$22,181	$28,747	$172,480	$334
5A.2	Elemental Sulfur Plant	$9,156	$1,817	$11,821	$0	$0	$22,794	$2,198	$0	$4,999	$29,991	$58
5A.3	Mercury Removal	$1,346	$0	$1,025	$0	$0	$2,371	$227	$119	$543	$3,260	$6
5A.4	Shift Reactors	$8,816	$0	$3,551	$0	$0	$12,367	$1,177	$0	$2,709	$16,253	$31
5A.5	Particulate Removal	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
5A.5	Blowback Gas Systems	$1,903	$320	$180	$0	$0	$2,403	$226	$0	$526	$3,155	$6
5A.6	Fuel Gas Piping	$0	$1,154	$795	$0	$0	$1,949	$178	$0	$425	$2,552	$5
5A.9	HGCU Foundations	$0	$1,142	$741	$0	$0	$1,883	$172	$0	$617	$2,672	$5
	SUBTOTAL 5A.	**$80,918**	**$4,433**	**$69,321**	**$0**	**$0**	**$154,672**	**$14,826**	**$22,300**	**$38,565**	**$230,362**	**$445**
5B	CO2 REMOVAL & COMPRESSION											
5B.1	CO2 Removal System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5B.2	CO2 Compression & Drying	$17,265	$0	$10,209	$0	$0	$27,475	$2,626	$0	$6,020	$36,121	$70
	SUBTOTAL 5B.	**$17,265**	**$0**	**$10,209**	**$0**	**$0**	**$27,475**	**$2,626**	**$0**	**$6,020**	**$36,121**	**$70**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$88,000	$0	$5,325	$0	$0	$93,325	$8,779	$9,332	$11,144	$122,580	$237
6.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.3	Compressed Air Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.9	Combustion Turbine Foundations	$0	$684	$762	$0	$0	$1,446	$135	$0	$474	$2,055	$4
	SUBTOTAL 6.	**$88,000**	**$684**	**$6,087**	**$0**	**$0**	**$94,771**	**$8,914**	**$9,332**	**$11,618**	**$124,635**	**$241**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$32,181	$0	$4,579	$0	$0	$36,760	$3,470	$0	$4,023	$44,253	$86
7.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$0	$1,627	$1,209	$0	$0	$2,836	$249	$0	$617	$3,702	$7
7.4	Stack	$3,222	$0	$1,211	$0	$0	$4,433	$422	$0	$485	$5,340	$10
7.9	HRSG,Duct & Stack Foundations	$0	$641	$620	$0	$0	$1,262	$117	$0	$414	$1,792	$3
	SUBTOTAL 7.	**$35,402**	**$2,268**	**$7,620**	**$0**	**$0**	**$45,291**	**$4,258**	**$0**	**$5,539**	**$55,087**	**$107**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$24,587	$0	$4,106	$0	$0	$28,693	$2,750	$0	$3,144	$34,587	$67
8.2	Turbine Plant Auxiliaries	$168	$0	$385	$0	$0	$554	$54	$0	$61	$668	$1
8.3	Condenser & Auxiliaries	$4,661	$0	$1,421	$0	$0	$6,082	$577	$0	$666	$7,325	$14
8.4	Steam Piping	$4,076	$0	$2,873	$0	$0	$6,949	$593	$0	$1,886	$9,428	$18
8.9	TG Foundations	$0	$828	$1,410	$0	$0	$2,238	$211	$0	$735	$3,184	$6
	SUBTOTAL 8.	**$33,492**	**$828**	**$10,195**	**$0**	**$0**	**$44,515**	**$4,184**	**$0**	**$6,491**	**$55,191**	**$107**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$4,467	$0	$981	$0	$0	$5,448	$516	$0	$895	$6,858	$13
9.2	Circulating Water Pumps	$1,405	$0	$88	$0	$0	$1,494	$128	$0	$243	$1,864	$4
9.3	Circ.Water System Auxiliaries	$124	$0	$18	$0	$0	$141	$13	$0	$23	$178	$0
9.4	Circ.Water Piping	$0	$5,260	$1,342	$0	$0	$6,602	$584	$0	$1,437	$8,624	$17
9.5	Make-up Water System	$322	$0	$456	$0	$0	$777	$74	$0	$170	$1,021	$2
9.6	Component Cooling Water Sys	$615	$736	$520	$0	$0	$1,871	$173	$0	$409	$2,453	$5
9.9	Circ.Water System Foundations& Structures	$0	$1,768	$3,027	$0	$0	$4,795	$452	$0	$1,574	$6,822	$13
	SUBTOTAL 9.	**$6,933**	**$7,764**	**$6,432**	**$0**	**$0**	**$21,129**	**$1,940**	**$0**	**$4,752**	**$27,821**	**$54**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Slag Dewatering & Cooling	$15,549	$0	$7,674	$0	$0	$23,223	$2,215	$0	$2,544	$27,981	$54
10.2	Gasifier Ash Depressurization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.3	Cleanup Ash Depressurization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.4	High Temperature Ash Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.5	Other Ash Rrecovery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$524	$0	$570	$0	$0	$1,094	$105	$0	$180	$1,379	$3
10.7	Ash Transport & Feed Equipment	$707	$0	$170	$0	$0	$877	$81	$0	$144	$1,101	$2
10.8	Misc. Ash Handling Equipment	$1,085	$1,329	$397	$0	$0	$2,811	$266	$0	$462	$3,539	$7
10.9	Ash/Spent Sorbent Foundation	$0	$46	$58	$0	$0	$104	$10	$0	$34	$148	$0
	SUBTOTAL 10.	**$17,865**	**$1,375**	**$8,869**	**$0**	**$0**	**$28,109**	**$2,676**	**$0**	**$3,363**	**$34,149**	**$66**

Exhibit 3-112 Case 6 Total Plant Cost Details (Continued)

Client: USDOE/NETL **Report Date:** 05-Apr-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 06 - Shell IGCC w/ CO2
Plant Size: 517.1 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct		Equipment	Material	Labor		Sales	Bare Erected	Eng'g CM	Contingencies		TOTAL PLANT COST	
No.	Item/Description	Cost	Cost	Direct	Indirect	Tax	Cost $	H.O.& Fee	Process	Project	$	$/kW
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$866	$0	$863	$0	$0	$1,729	$164	$0	$189	$2,083	$4
11.2	Station Service Equipment	$4,130	$0	$388	$0	$0	$4,518	$429	$0	$495	$5,442	$11
11.3	Switchgear & Motor Control	$7,893	$0	$1,447	$0	$0	$9,340	$865	$0	$1,531	$11,735	$23
11.4	Conduit & Cable Tray	$0	$376	$12,191	$0	$0	$12,567	$1,524	$0	$3,523	$17,614	$34
11.5	Wire & Cable	$0	$6,897	$4,639	$0	$0	$11,536	$843	$0	$3,095	$15,474	$30
11.6	Protective Equipment	$0	$627	$2,378	$0	$0	$3,005	$294	$0	$495	$3,793	$7
11.7	Standby Equipment	$208	$0	$211	$0	$0	$419	$40	$0	$69	$529	$1
11.8	Main Power Transformers	$9,858	$0	$132	$0	$0	$9,990	$757	$0	$1,612	$12,358	$24
11.9	Electrical Foundations	$0	$142	$376	$0	$0	$518	$49	$0	$170	$737	$1
	SUBTOTAL 11.	**$22,955**	**$8,041**	**$22,625**	**$0**	**$0**	**$53,621**	**$4,967**	**$0**	**$11,178**	**$69,766**	**$135**
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
12.3	Steam Turbine Control	w/8.1	$0	w/8.1	$0	$0	$0	$0	$0	$0	$0	$0
12.4	Other Major Component Control	$1,006	$0	$700	$0	$0	$1,706	$164	$85	$293	$2,249	$4
12.5	Signal Processing Equipment	W/12.7	$0	W/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.6	Control Boards,Panels & Racks	$231	$0	$154	$0	$0	$386	$37	$19	$88	$531	$1
12.7	Computer & Accessories	$5,368	$0	$179	$0	$0	$5,547	$526	$277	$635	$6,985	$14
12.8	Instrument Wiring & Tubing	$0	$1,908	$3,994	$0	$0	$5,902	$500	$295	$1,674	$8,372	$16
12.9	Other I & C Equipment	$3,588	$0	$1,815	$0	$0	$5,403	$518	$270	$929	$7,121	$14
	SUBTOTAL 12.	**$10,193**	**$1,908**	**$6,843**	**$0**	**$0**	**$18,945**	**$1,746**	**$947**	**$3,620**	**$25,258**	**$49**
13	Improvements to Site											
13.1	Site Preparation	$0	$101	$2,167	$0	$0	$2,267	$223	$0	$747	$3,238	$6
13.2	Site Improvements	$0	$1,790	$2,396	$0	$0	$4,186	$411	$0	$1,379	$5,976	$12
13.3	Site Facilities	$3,207	$0	$3,410	$0	$0	$6,617	$650	$0	$2,180	$9,446	$18
	SUBTOTAL 13.	**$3,207**	**$1,890**	**$7,973**	**$0**	**$0**	**$13,070**	**$1,284**	**$0**	**$4,306**	**$18,660**	**$36**
14	Buildings & Structures											
14.1	Combustion Turbine Area	$0	$221	$127	$0	$0	$348	$31	$0	$76	$454	$1
14.2	Steam Turbine Building	$0	$2,059	$2,972	$0	$0	$5,031	$462	$0	$824	$6,316	$12
14.3	Administration Building	$0	$814	$598	$0	$0	$1,412	$126	$0	$231	$1,768	$3
14.4	Circulation Water Pumphouse	$0	$153	$82	$0	$0	$235	$21	$0	$38	$294	$1
14.5	Water Treatment Buildings	$0	$457	$452	$0	$0	$909	$82	$0	$149	$1,140	$2
14.6	Machine Shop	$0	$416	$289	$0	$0	$705	$63	$0	$115	$883	$2
14.7	Warehouse	$0	$672	$440	$0	$0	$1,112	$98	$0	$182	$1,392	$3
14.8	Other Buildings & Structures	$0	$403	$318	$0	$0	$721	$64	$0	$157	$942	$2
14.9	Waste Treating Building & Str.	$0	$900	$1,744	$0	$0	$2,644	$246	$0	$578	$3,467	$7
	SUBTOTAL 14.	**$0**	**$6,095**	**$7,021**	**$0**	**$0**	**$13,117**	**$1,192**	**$0**	**$2,349**	**$16,657**	**$32**
	TOTAL COST	**$715,547**	**$62,824**	**$259,009**	**$0**	**$0**	**$1,037,381**	**$96,266**	**$52,591**	**$193,286**	**$1,379,524**	**$2,668**

Exhibit 3-113 Case 6 Initial and Annual Operating and Maintenance Costs

INITIAL & ANNUAL O&M EXPENSES							
Case 06 - Shell IGCC w/ CO2						Cost Base (Dec)	2006
						Heat Rate-net(Btu/kWh):	10,674
						MWe-net:	517
						Capacity Factor: (%):	80
OPERATING & MAINTENANCE LABOR							
Operating Labor							
Operating Labor Rate(base):	33.00 $/hour						
Operating Labor Burden:	30.00 % of base						
Labor O-H Charge Rate:	25.00 % of labor						
			Total				
Skilled Operator	2.0		2.0				
Operator	10.0		10.0				
Foreman	1.0		1.0				
Lab Tech's, etc.	3.0		3.0				
TOTAL-O.J.'s	16.0		16.0				
						Annual Cost $	Annual Unit Cost $/kW-net
Annual Operating Labor Cost						$6,012,864	$11.627
Maintenance Labor Cost						$12,084,712	$23.369
Administrative & Support Labor						$4,524,394	$8.749
TOTAL FIXED OPERATING COSTS						**$22,621,970**	**$43.745**
VARIABLE OPERATING COSTS							
							$/kWh-net
Maintenance Material Cost						**$22,581,355**	**$0.00623**
Consumables	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost			
Water(/1000 gallons)	0	6,551	1.03	**$0**		**$1,970,146**	**$0.00054**
Chemicals							
MU & WT Chem.(lb)	136,592	19,513	0.16	$22,510		$939,005	$0.00026
Carbon (Mercury Removal) (lb)	130,280	178	1.00	$130,280		$51,976	$0.00001
COS Catalyst (m3)	0	0	0.96	$0		$0	$0.00000
Water Gas Shift Catalyst(ft3)	6,922	4.74	475.00	$3,287,950		$657,438	$0.00018
Selexol Solution (gal.)	469	67	12.90	$6,051		$252,397	$0.00007
MDEA Solution (gal)	0	0	0.96	$0		$0	$0.00000
Sulfinol Solution (gal)	0	0	9.68	$0		$0	$0.00000
SCR Catalyst (m3)	0	0	0.00	$0		$0	$0.00000
Aqueous Ammonia (ton)	0	0	0.00	$0		$0	$0.00000
Claus Catalyst(ft3)	w/equip.	2.14	125.00	$0		$78,110	$0.00002
Subtotal Chemicals				**$3,446,791**		**$1,978,926**	**$0.00055**
Other							
Supplemental Fuel(MBtu)	0	0	0.00	$0		$0	$0.00000
Gases,N2 etc.(/100scf)	0	0	0.00	$0		$0	$0.00000
L.P. Steam(/1000 pounds)	0	0	0.00	$0		$0	$0.00000
Subtotal Other				**$0**		**$0**	**$0.00000**
Waste Disposal							
Spent Mercury Catalyst (lb)	0	178	0.40	$0		$20,874	$0.00001
Flyash (ton)	0	0	0.00	$0		$0	$0.00000
Bottom Ash(ton)	0	568	15.45	$0		$2,561,970	$0.00071
Subtotal-Waste Disposal				**$0**		**$2,582,844**	**$0.00071**
By-products & Emissions							
Sulfur(tons)	0	142	0.00	$0		$0	$0.00000
Subtotal By-Products				**$0**		**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$3,446,791**		**$29,113,271**	**$0.00803**
Fuel(ton)	170,338	5,678	42.11	**$7,172,945**		**$69,816,668**	**$0.01926**

3.5 IGCC CASE SUMMARY

The performance results of the six IGCC plant configurations modeled in this study are summarized in Exhibit 3-114.

Exhibit 3-114 Estimated Performance and Cost Results for IGCC Cases

	Integrated Gasification Combined Cycle					
	GEE		CoP		Shell	
	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
CO_2 Capture	No	Yes	No	Yes	No	Yes
Gross Power Output (kW_e)	770,350	744,960	742,510	693,840	748,020	693,555
Auxiliary Power Requirement (kW_e)	130,100	189,285	119,140	175,600	112,170	176,420
Net Power Output (kW_e)	640,250	555,675	623,370	518,240	635,850	517,135
Coal Flowrate (lb/hr)	489,634	500,379	463,889	477,855	452,620	473,176
Natural Gas Flowrate (lb/hr)	N/A	N/A	N/A	N/A	N/A	N/A
HHV Thermal Input (kW_{th})	1,674,044	1,710,780	1,586,023	1,633,771	1,547,493	1,617,772
Net Plant HHV Efficiency (%)	38.2%	32.5%	39.3%	31.7%	41.1%	32.0%
Net Plant HHV Heat Rate (Btu/kW-hr)	8,922	10,505	8,681	10,757	8,304	10,674
Raw Water Usage, gpm	4,003	4,579	3,757	4,135	3,792	4,563
Total Plant Cost ($ x 1,000)	1,160,919	1,328,209	1,080,166	1,259,883	1,256,810	1,379,524
Total Plant Cost ($/kW)	1,813	2,390	1,733	2,431	1,977	2,668
LCOE (mills/kWh)[1]	78.0	102.9	75.3	105.7	80.5	110.4
CO_2 Emissions (lb/MWh)[2]	1,459	154	1,452	189	1,409	149
CO_2 Emissions (lb/MWh)[3]	1,755	206	1,730	253	1,658	199
SO_2 Emissions (lb/MWh)[2]	0.0942	0.0751	0.0909	0.0686	0.0878	0.0837
NOx Emissions (lb/MWh)[2]	0.406	0.366	0.433	0.400	0.413	0.388
PM Emissions (lb/MWh)[2]	0.053	0.056	0.052	0.057	0.050	0.057
Hg Emissions (lb/MWh)[2]	4.24E-06	4.48E-06	4.16E-06	4.59E-06	4.03E-06	4.55E-06

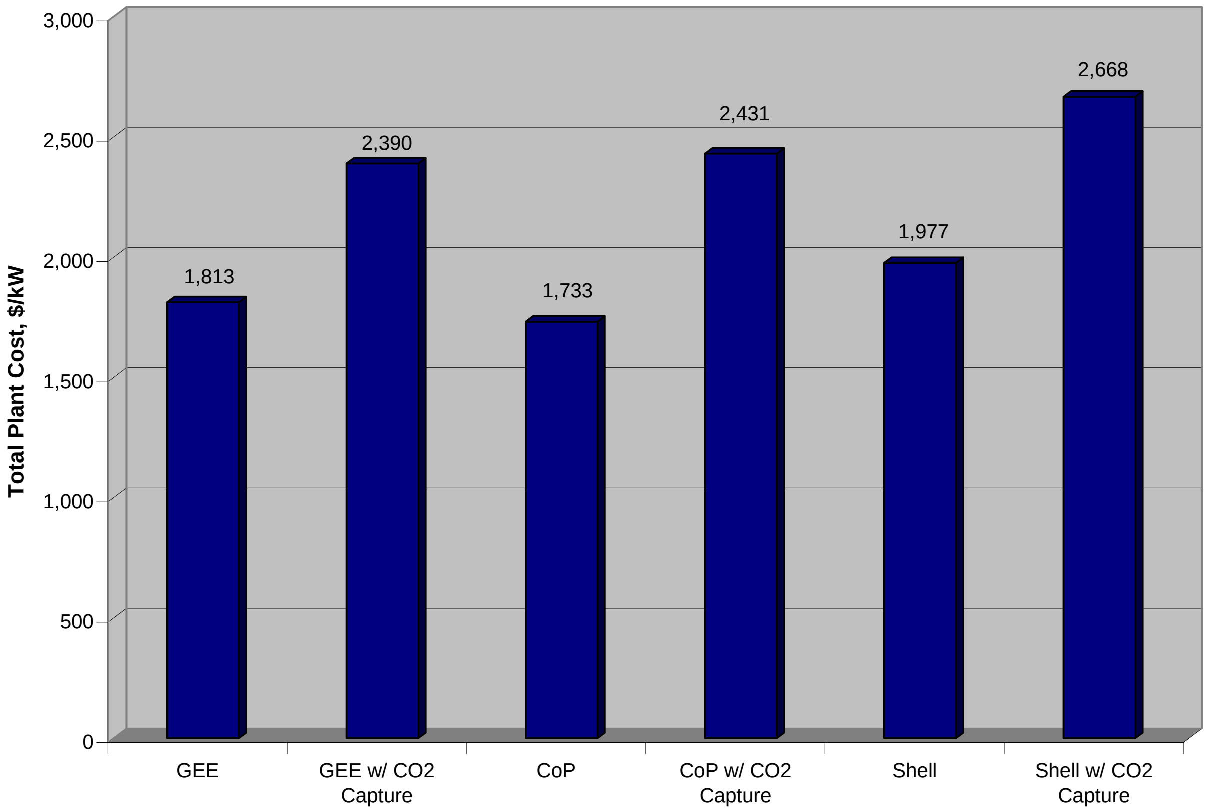
[1] Based on an 80% capacity factor
[2] Value is based on gross output
[3] Value is based on net output

The TPC of the six IGCC cases is shown in Exhibit 3-115. The following observations are made with the caveat that the differences between cases are less than the estimate accuracy (± 30 percent). However, all cases are evaluated using a common set of technical and economic assumptions allowing meaningful comparisons among the cases:

- CoP has the lowest capital cost among the non-capture cases. The E-Gas technology has several features that lend it to being lower cost, such as:
    - The firetube syngas cooler is much smaller and less expensive than a radiant section. E-Gas can use a firetube boiler because the two-stage design reduces the gas temperature (slurry quench) and drops the syngas temperature into a range where a radiant cooler is not needed.
    - The firetube syngas cooler sits next to the gasifier instead of above or below it which reduces the height of the main gasifier structure. The E-Gas proprietary slag removal system, used instead of lock hoppers below the gasifier, also contributes to the lower structure height.

  The TPC of the GEE gasifier is about 5 percent greater than CoP and Shell is about 12 percent higher.

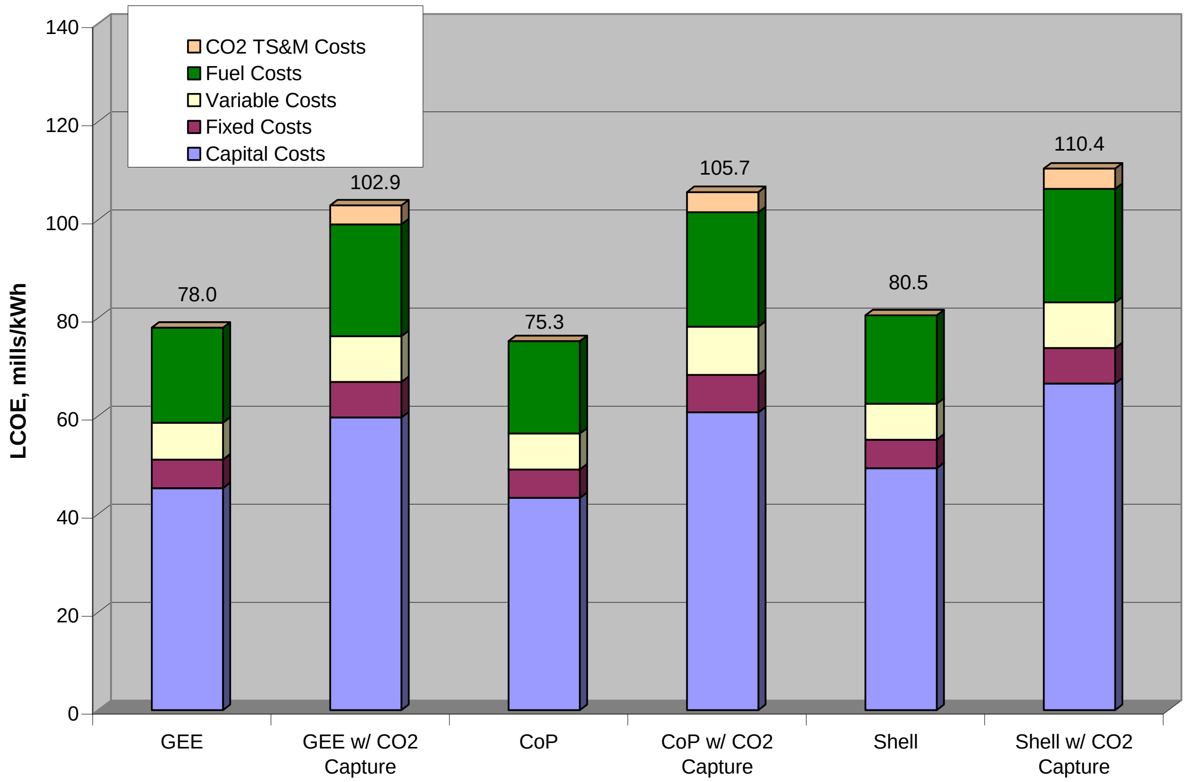
Exhibit 3-115 TPC for IGCC Cases



- The GEE gasifier is the low cost technology in the CO_2 capture cases, with CoP about 2 percent higher and Shell about 12 percent higher. The greatest uncertainty in all of the capital cost estimates is for the Shell capture case which is based on a water quench process (instead of syngas recycle) that has been proposed by Shell in a patent application. [53] However, to date there have been no commercial applications of this configuration.
- The ASU cost represents on average 14 percent of the TPC (range from 12.6-15.8 percent). The ASU cost includes oxygen and nitrogen compression, and in the non-capture cases, also includes the cost of the combustion turbine extraction air heat exchanger. With nitrogen dilution used to the maximum extent possible, nitrogen compression costs are significant.
- The capital cost premium for adding CO_2 capture averages 36 percent ($2,496/kW versus $1,841/kW).

The 20-year LCOE is shown for the IGCC cases in Exhibit 3-116.

Exhibit 3-116 LCOE for IGCC Cases



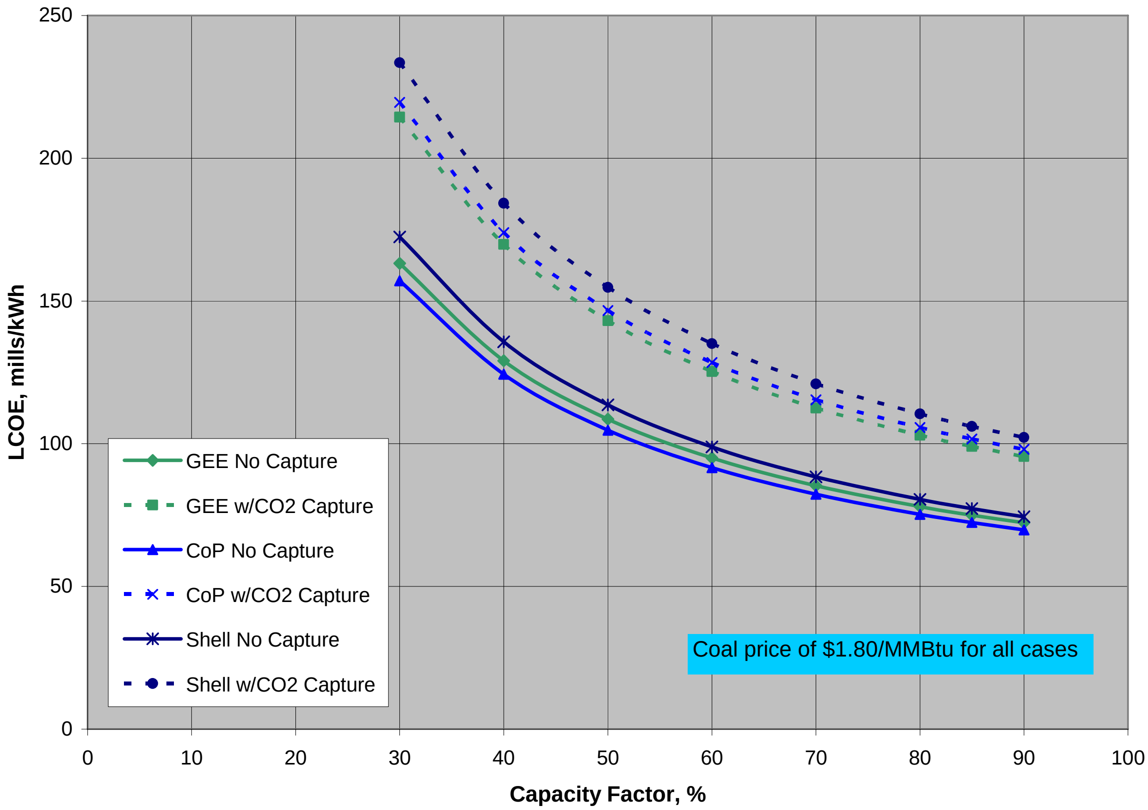
The following observations can be made:

- The LCOE is dominated by capital costs, at least 57 percent of the total in all cases.
- In the non-capture cases the CoP gasifier has the lowest LCOE, but the differential with Shell is reduced (compared to the TPC) primarily because of the higher efficiency of the Shell gasifier. The Shell LCOE is 7 percent higher than CoP (compared to 12 percent higher TPC). The GEE gasifier LCOE is about 3.5 percent higher than CoP.
- In the capture cases the variation in LCOE is small, however the order of the GEE and CoP gasifiers is reversed. The range is from 102.9 mills/kWh for GEE to 110.4 mills/kWh for Shell with CoP intermediate at 105.7 mills/kWh. The LCOE CO_2 capture premium for the IGCC cases averages 36 percent (range of 32 to 40 percent).
- The CO_2 TS&M LCOE component comprises less than 4 percent of the total LCOE in all capture cases.

The effect of capacity factor and coal price on LCOE is shown in Exhibit 3-117 and Exhibit 3-118, respectively.

The assumption implicit in Exhibit 3-117 is that each gasifier technology can achieve a capacity factor of up to 90 percent with no additional capital equipment. The cost differential between technologies decreases as capacity factor increases. At low capacity factor the capital cost differential is more magnified and the spread between technologies increases slightly.

Exhibit 3-117 Capacity Factor Sensitivity of IGCC Cases



LCOE is relatively insensitive to fuel costs for the IGCC cases as shown in Exhibit 3-118. A tripling of coal price from 1 to $3/MMBtu results in an average LCOE increase of only about 26-31 percent for all cases.

As presented in Section 2.4 the cost of CO_2 capture was calculated in two ways, CO_2 removed and CO_2 avoided. The results for the IGCC carbon capture cases are shown in Exhibit 3-119. The cost of CO_2 removed averages $30/ton for the three IGCC cases with a range of $27-$32/ton. The CoP and Shell gasifier cases have nearly identical results but for different reasons. In the CoP case the cost per ton of CO_2 removed is higher than GEE primarily because it has the lowest CO_2 removal efficiency due to the higher syngas CH_4 content. The Shell case is higher than GEE because it has the highest LCOE of the three gasifiers.

The cost of CO_2 avoided averages $39/ton with a range of $32-$42/ton. The cost of CO_2 avoided follows the same trends as CO_2 removed for the same reasons.

Exhibit 3-118 Coal Price Sensitivity of IGCC Cases

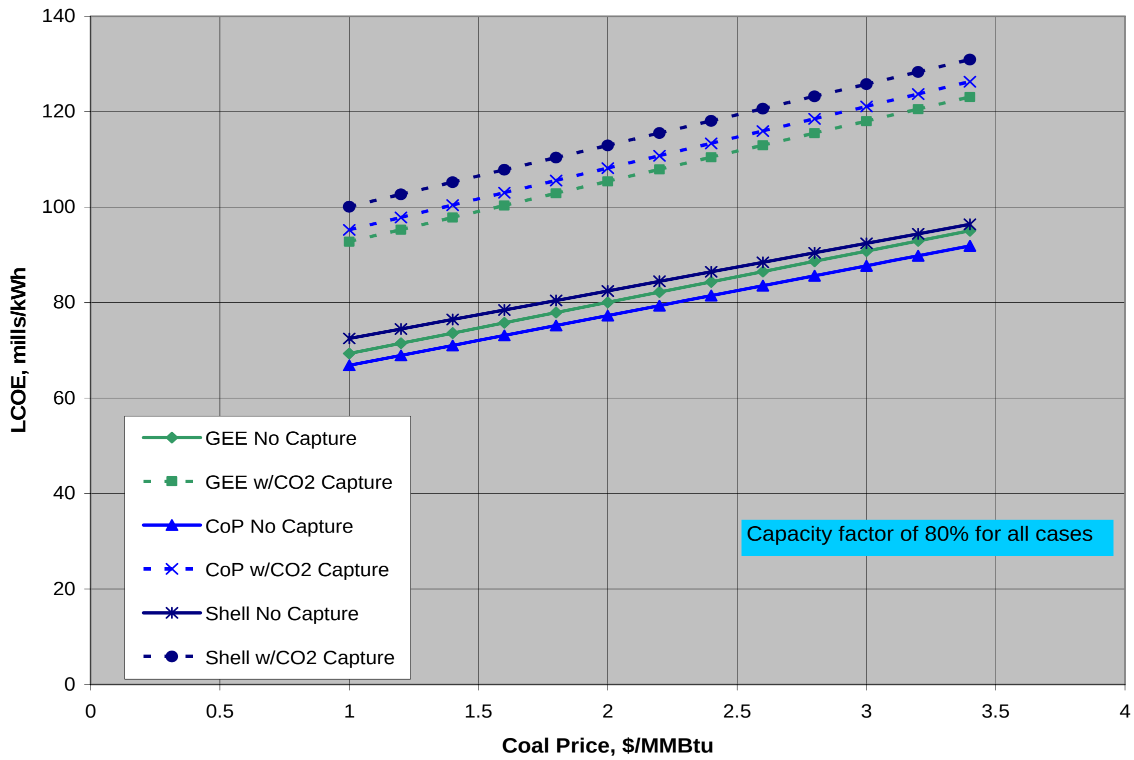
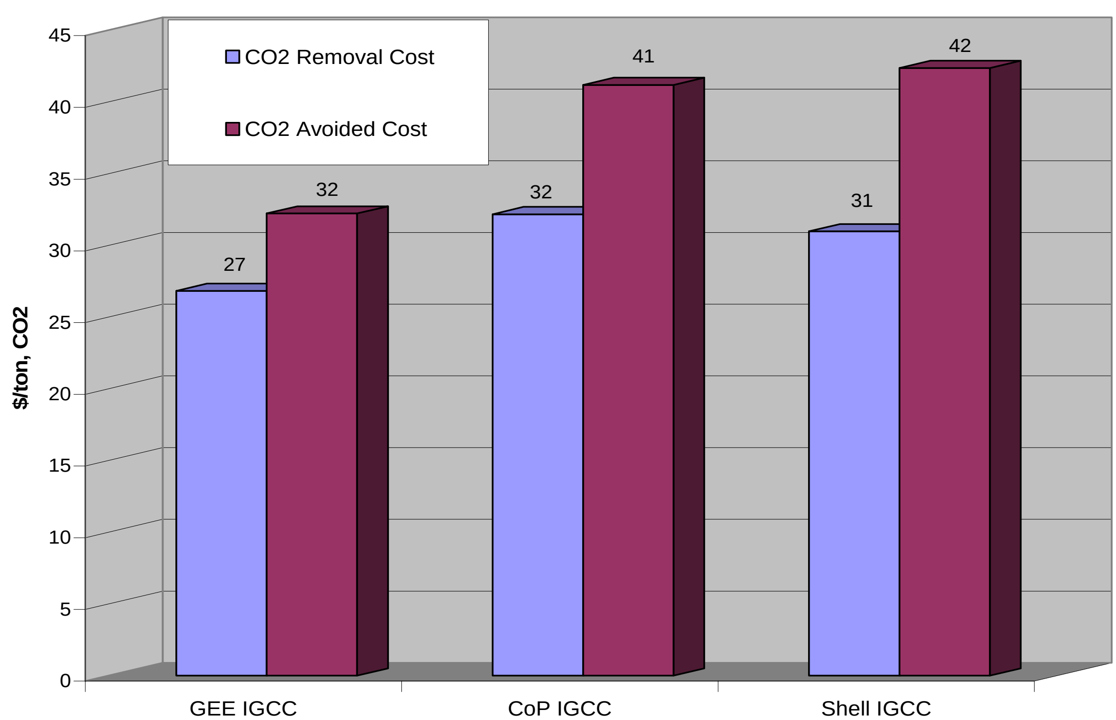


Exhibit 3-119 Cost of CO_2 Captured and Avoided in IGCC Cases



The following observations can be made regarding plant performance:

- In the non-carbon capture cases the dry fed Shell gasifier has the highest net plant efficiency (41.1 percent), followed by the two-stage CoP slurry fed gasifier (39.3 percent) and the single-stage GEE gasifier (38.2 percent). The absolute values of the GEE and CoP gasifiers are close to the reported values per the vendors. [50, 51] The Shell efficiency is slightly lower than reported by the vendor in other recent presentations. [52]
- In the carbon capture cases the efficiency of the three gasifiers is nearly equal, ranging from 31.7 to 32.5 percent.
- The dry fed Shell gasifier experiences the largest energy penalty (9.1 percent) primarily because addition of the steam required for the water gas shift reaction is provided as quench water to reduce the syngas temperature from 1427°C (2600°F) to 399°C (750°F). Quench to 399°C (750°F) reduces the amount of heat recovered in the syngas cooler relative to the non-capture case where syngas recycle reduces the temperature to only 891°C (1635°F) prior to the cooler. The CO_2 capture scheme used in this study for the Shell process is similar to one described in a recent Shell patent application. [53]
- The CoP process experiences the second largest energy penalty (7.6 percent) primarily because, like the Shell case, a significant amount of water must be added to the syngas for the SGS reactions.
- The energy penalty for the GEE gasifier with CO_2 capture is 5.7 percent. The smaller energy penalty results from the large amount of water already in the syngas from the quench step prior to SGS. While the quench limits the efficiency in the non-capture case, it is the primary reason that the net efficiency is slightly greater than CoP and Shell in the CO_2 capture case.
- The assumed carbon conversion efficiency in this study for the three gasifiers results in differing amount of carbon in the slag. Exhibit 3-120 shows carbon conversion and slag carbon content. Carbon capture efficiency is reported based on the amount of carbon entering the system with the coal less the carbon exiting the gasifier with the slag.

Exhibit 3-120 Carbon Conversion Efficiency and Slag Carbon Content

Gasifier Vendor	Carbon Conversion, %	Slag Carbon Content, wt%
GEE	98.0	11.66
CoP	99.2	4.70
Shell	99.5	3.19

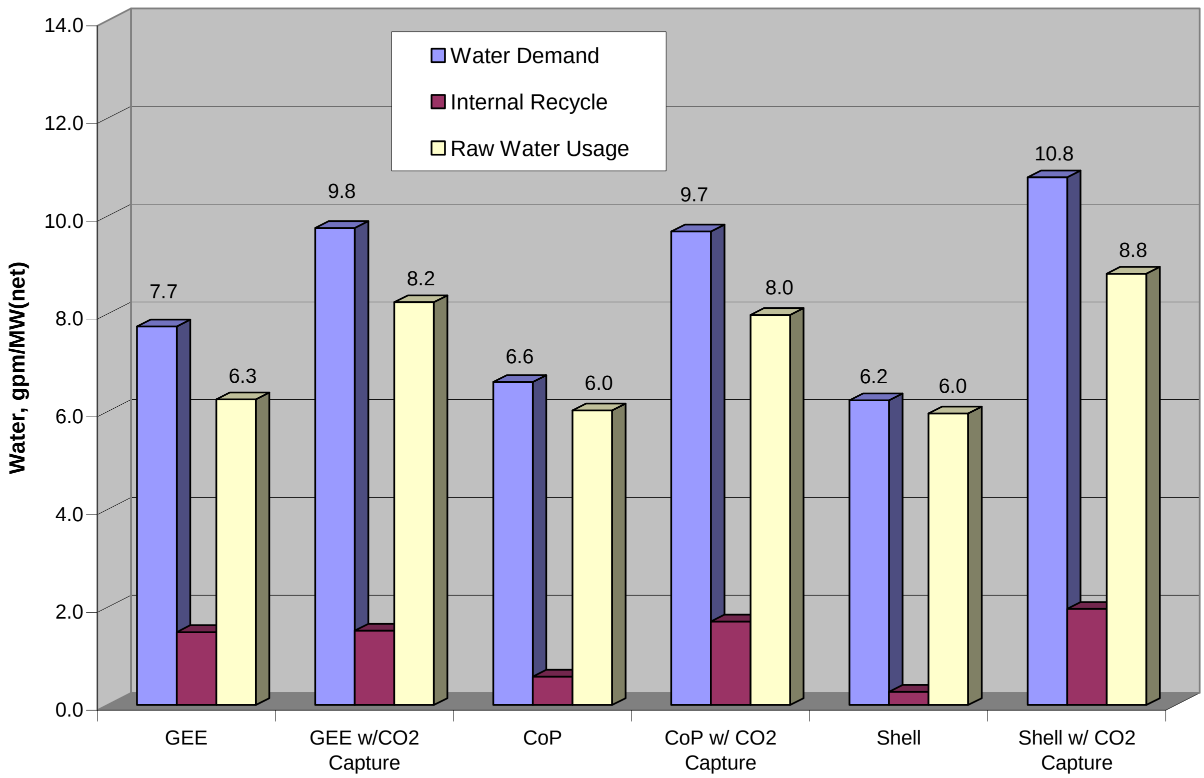
- Particulate emissions and Hg emissions are essentially the same for all six IGCC cases. The environmental target for particulate emissions is 0.0071 lb/MMBtu, and it was assumed that the combination of particulate control used by each technology could meet this limit. Similarly, the carbon beds used for mercury control were uniformly assumed to achieve 95 percent removal. The small variation in Hg emissions is due to a similar small variation in coal feed rate among the six cases. In all cases the Hg emissions are substantially below the NSPS requirement of 20 x 10^{-6} lb/MWh. Had 90 percent been chosen for the Hg removal efficiency, all six cases would still have had emissions less than half of the NSPS limit.

- Based on vendor data, it was assumed that the advanced F class turbine would achieve 15 ppmv NOx emissions at 15 percent O_2 for both “standard” syngas in the non-capture cases and for high hydrogen syngas in the CO_2 capture cases. The NOx emissions are slightly lower in the three capture cases (compared to non-capture) because of the lower syngas volume generated in high hydrogen syngas cases.
- The environmental target for SO_2 emissions is 0.0128 lb/MMBtu. Vendor quotes confirmed that each of the AGR processes, Selexol, refrigerated MDEA and Sulfinol-M, could meet the limit. The two-stage Selexol process used for each of the CO_2 capture cases resulted in lower SO_2 emissions because the unit was designed to meet the CO_2 removal requirement. The CoP gasifier has the lowest SO_2 emissions among CO_2 capture cases because of maximizing CO_2 capture to compensate for the higher CH_4 concentration in the CoP raw syngas.

Water demand, internal recycle and water usage, all normalized by net output, are presented in Exhibit 3-121. The following observations can be made:

- Raw water usage for all cases is dominated by cooling tower makeup requirements, which accounts for 84-92 percent of raw water usage in non-capture cases and 71-78 percent in CO_2 capture cases.
- Normalized water demand for the GEE non-capture case is 17 percent higher than the CoP non-capture case and 24 percent higher than the Shell non-capture case primarily because of the large quench water requirement. However, because much of the quench water is subsequently recovered as condensate as the syngas is cooled, the raw water usage of the GEE process is only 3.7 percent higher than CoP and 4.8 percent higher than Shell.
- The Shell non-capture case has the lowest normalized water demand, but is approximately equal to CoP in normalized raw water usage because very little water is available to recover for internal recycle in the Shell system. The GEE normalized raw water usage is slightly higher than CoP and Shell primarily because the larger steam turbine output leads to higher cooling tower makeup requirements.
- The normalized water demand for the three CO_2 capture cases varies by only 11 percent from the highest to the lowest. The variation between cases is small because each technology requires approximately the same amount of water in the syngas prior to the shift reactors. The difference in technologies is where and how the water is introduced. Much of the water is introduced in the quench sections of the GEE and Shell cases while steam is added in the CoP case.
- The normalized raw water usage in the CO_2 capture cases also shows little variation with CoP the lowest, GEE only 3.3 percent higher and Shell about 10 percent higher. The main reason for the lower CoP water requirement is less cooling tower makeup is required because a significant amount of extraction steam is used for the SGS shift reaction.

Exhibit 3-121 Water Usage in IGCC Cases



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4 PULVERIZED COAL RANKINE CYCLE PLANTS

Four pulverized coal-fired (PC) Rankine cycle power plant configurations were evaluated and the results are presented in this section. Each design is based on a market-ready technology that is assumed to be commercially available in time to support a 2010 start up date. All designs employ a one-on-one configuration comprised of a state-of-the art pulverized coal steam generator firing Illinois No. 6 coal and a steam turbine.

The PC cases are evaluated with and without carbon capture on a common 550 MWe net basis. The designs that include carbon capture have a larger gross unit size to compensate for the higher auxiliary loads. The constant net output sizing basis is selected because it provides for a meaningful side-by-side comparison of the results. The boiler and steam turbine industry ability to match unit size to a custom specification has been commercially demonstrated enabling common net output comparison of the PC cases in this study. As discussed in Section 3, this was not possible in the IGCC cases because of the fixed output from the combustion turbine. However, the net output from the PC cases falls in the range of outputs from the IGCC cases, which average 530 MW for CO_2 capture cases and 630 MW for non-capture cases.

Steam conditions for the Rankine cycle cases were selected based on a survey of boiler and steam turbine original equipment manufacturers (OEM), who were asked for the most advanced steam conditions that they would guarantee for a commercial project in the US with subcritical and supercritical PC units rated at nominal 550 MWe net capacities and firing Illinois No. 6 coal [54]. Based on the OEM responses, the following single-reheat steam conditions were selected for the study:

- For subcritical cycle cases (9 and 10) – 16.5 MPa/566°C/566°C (2400 psig/1050°F/1050°F)
- For supercritical cases (11 and 12) – 24.1 MPa/593°C/593°C (3500 psig/1100°F/1100°F)

While the current DOE program for the ultra supercritical cycle materials development targets 732°C/760°C (1350ºF/1400ºF) at 34.5 MPa (5000 psi) cycle conditions to be available by 2015, and a similar Thermie program in the European Union (EU) has targeted 700°C/720°C (1292ºF/1328ºF) at about 29.0 MPa (4200 psi) [55], steam temperature selection for boilers depends upon fuel corrosiveness. Most of the contacted OEMs were of the opinion that the steam conditions in this range would be limited to low sulfur coal applications (such as PRB). Their primary concern is that elevated temperature operation while firing high sulfur coal (such as Illinois No. 6) would result in an exponential increase of the material wastage rates of the highest temperature portions of the superheater and reheater due to coal ash corrosion, requiring pressure parts replacement outages approximately every 10 or 15 years. This cost would offset the value of fuel savings and emissions reduction due to the higher efficiency. The availability/reliability of the more exotic materials required to support the elevated temperature environment for high sulfur/chlorine applications, while extensively demonstrated in the laboratory [56], has not been commercially demonstrated. In addition, the three most recently built supercritical units in North America have steam cycles similar to this study's design basis, namely Genesee Phase 3 in Canada, which started operations in 2004 (25.0 MPa/570°C/568°C [3625 psia/1058°F/1054°F]), Council Bluffs 4 in the United States, which is currently under construction (25.4 MPa/566°C/593°C [3690 psia/1050°F/1100°F]), and Oak Creek 1 and 2, which are currently under construction (24.1 MPa/566°C [3500 psig/1050°F]).

The evaluation basis details, including site ambient conditions, fuel composition and the emissions control basis, are provided in Section 2 of this report.

4.1 PC COMMON PROCESS AREAS

The PC cases have process areas which are common to each plant configuration such as coal receiving and storage, emissions control technologies, power generation, etc. As detailed descriptions of these process areas in each case section would be burdensome and repetitious, they are presented in this section for general background information. The performance features of these sections are then presented in the case-specific sections.

4.1.1 COAL AND SORBENT RECEIVING AND STORAGE

The function of the coal portion of the Coal and Sorbent Receiving and Storage system for PC plants is identical to the IGCC facilities. It is to provide the equipment required for unloading, conveying, preparing, and storing the fuel delivered to the plant. The scope of the system is from the trestle bottom dumper and coal receiving hoppers up to the coal storage silos. The system is designed to support short-term operation at the 5 percent over pressure/valves wide open (OP/VWO) condition (16 hours) and long-term operation of 90 days or more at the maximum continuous rating (MCR).

The scope of the sorbent receiving and storage system includes truck roadways, turnarounds, unloading hoppers, conveyors and the day storage bin.

Operation Description - The coal is delivered to the site by 100-car unit trains comprised of 91 tonne (100 ton) rail cars. The unloading is done by a trestle bottom dumper, which unloads the coal into two receiving hoppers. Coal from each hopper is fed directly into a vibratory feeder. The 8 cm x 0 (3" x 0) coal from the feeder is discharged onto a belt conveyor. Two conveyors with an intermediate transfer tower are assumed to convey the coal to the coal stacker, which transfer the coal to either the long-term storage pile or to the reclaim area. The conveyor passes under a magnetic plate separator to remove tramp iron and then to the reclaim pile.

Coal from the reclaim pile is fed by two vibratory feeders, located under the pile, onto a belt conveyor, which transfers the coal to the coal surge bin located in the crusher tower. The coal is reduced in size to 2.5 cm x 0 (1" x 0) by the coal crushers. The coal is then transferred by conveyor to the transfer tower. In the transfer tower the coal is routed to the tripper that loads the coal into one of the six boiler silos.

Limestone is delivered to the site using 23 tonne (25 ton) trucks. The trucks empty into a below grade hopper where a feeder transfers the limestone to a conveyor for delivery to the storage pile. Limestone from the storage pile is transferred to a reclaim hopper and conveyed to a day bin.

4.1.2 STEAM GENERATOR AND ANCILLARIES

The steam generator for the subcritical PC plants is a drum-type, wall-fired, balanced draft, natural circulation, totally enclosed dry bottom furnace, with superheater, reheater, economizer and air-heater.

The steam generator for the supercritical plants is a once-through, spiral-wound, Benson-boiler, wall-fired, balanced draft type unit with a water-cooled dry bottom furnace. It includes superheater, reheater, economizer, and air heater.

It is assumed for the purposes of this study that the power plant is designed to be operated as a base-loaded unit but with some consideration for daily or weekly cycling, as can be cost effectively included in the base design.

The combustion systems for both subcritical and supercritical steam conditions are equipped with LNBs and OFA. It is assumed for the purposes of this study that the power plant is designed for operation as a base-load unit.

Scope

The steam generator comprises the following for both subcritical and supercritical PCs:

- Drum-type evaporator (subcritical only)
- Once-through type steam generator (supercritical only)
- Startup circuit, including integral separators (supercritical only)
- Water-cooled furnace, dry bottom
- Two-stage superheater
- Reheater
- Economizer
- Spray type desuperheater
- Soot blower system
- Air preheaters (Ljungstrom type)
- Coal feeders and pulverizers
- Low NOx Coal burners and light oil ignitors/ warmup system
- Overfire air system
- Forced draft (FD) fans
- Primary air (PA) fans
- Induced draft (ID) fans

The steam generator operates as follows:

Feedwater and Steam

For the subcritical steam system feedwater enters the economizer, recovers heat from the combustion gases exiting the steam generator, and then passes to the boiler drum, from where it is distributed to the water wall circuits enclosing the furnace. After passing through the lower and upper furnace circuits and steam drum in sequence, the steam passes through the convection enclosure circuits to the primary superheater and then to the secondary superheater.

The steam then exits the steam generator en route to the HP turbine. Steam from the HP turbine returns to the steam generator as cold reheat and returns to the IP turbine as hot reheat.

For the supercritical steam system feedwater enters the bottom header of the economizer and passes upward through the economizer tube bank, through stringer tubes which support the primary superheater, and discharges to the economizer outlet headers. From the outlet headers, water flows to the furnace hopper inlet headers via external downcomers. Water then flows upward through the furnace hopper and furnace wall tubes. From the furnace, water flows to the steam water separator. During low load operation (operation below the Benson point), the water from the separator is returned to the economizer inlet with the boiler recirculating pump. Operation at loads above the Benson point is once through.

Steam flows from the separator through the furnace roof to the convection pass enclosure walls, primary superheater, through the first stage of water attemperation, to the furnace platens. From the platens, the steam flows through the second stage of attemperation and then to the intermediate superheater. The steam then flows to the final superheater and on to the outlet pipe terminal. Two stages of spray attemperation are used to provide tight temperature control in all high temperature sections during rapid load changes.

Steam returning from the turbine passes through the primary reheater surface, then through crossover piping containing inter-stage attemperation. The crossover piping feeds the steam to the final reheater banks and then out to the turbine. Inter-stage attemperation is used to provide outlet temperature control during load changes.

Air and Combustion Products

Combustion air from the FD fans is heated in Ljungstrom type air preheaters, recovering heat energy from the exhaust gases exiting the boiler. This air is distributed to the burner windbox as secondary air. Air for conveying pulverized coal to the burners is supplied by the PA fans. This air is heated in the Ljungstrom type air preheaters to permit drying of the pulverized coal, and a portion of the air from the PA fans bypasses the air preheaters to be used for regulating the outlet coal/air temperature leaving the mills.

The pulverized coal and air mixture flows to the coal nozzles at various elevations of the furnace. The hot combustion products rise to the top of the boiler and pass through the superheater and reheater sections. The gases then pass through the economizer and air preheater. The gases exit the steam generator at this point and flow to the SCR reactor, fabric filter, ID fan, FGD system, and stack.

Fuel Feed

The crushed Illinois No. 6 bituminous coal is fed through feeders to each of the mills (pulverizers), where its size is reduced to approximately 72% passing 200 mesh and less than 0.5% remaining on 50 mesh [57]. The pulverized coal exits each mill via the coal piping and is distributed to the coal nozzles in the furnace walls using air supplied by the PA fans.

Ash Removal

The furnace bottom comprises several hoppers, with a clinker grinder under each hopper. The hoppers are of welded steel construction, lined with refractory. The hopper design incorporates a water-filled seal trough around the upper periphery for cooling and sealing. Water and ash discharged from the hopper pass through the clinker grinder to an ash sluice system for conveyance to hydrobins, where the ash is dewatered before it is transferred to trucks for offsite disposal. The description of the balance of the bottom ash handling system is presented in Section 4.1.9. The steam generator incorporates fly ash hoppers under the economizer outlet and air heater outlet.

Burners

A boiler of this capacity employs approximately 24 to 36 coal nozzles arranged at multiple elevations. Each burner is designed as a low-NOx configuration, with staging of the coal combustion to minimize NOx formation. In addition, overfire air nozzles are provided to further stage combustion and thereby minimize NOx formation.

Oil-fired pilot torches are provided for each coal burner for ignition, warm-up and flame stabilization at startup and low loads.

Air Preheaters

Each steam generator is furnished with two vertical-shaft Ljungstrom regenerative type air preheaters. These units are driven by electric motors through gear reducers.

Soot Blowers

The soot-blowing system utilizes an array of 50 to 150 retractable nozzles and lances that clean the furnace walls and convection surfaces with jets of high-pressure steam. The blowers are sequenced to provide an effective cleaning cycle depending on the coal quality and design of the furnace and convection surfaces. Electric motors drive the soot blowers through their cycles.

4.1.3 NO_X CONTROL SYSTEM

The plant is designed to achieve the environmental target of 0.07 lb NOx/MMBtu. Two measures are taken to reduce the NOx. The first is a combination of low-NOx burners and the introduction of staged overfire air in the boiler. The low-NOx burners and overfire air reduce the emissions to about 0.5 lb/MMBtu.

The second measure taken to reduce the NOx emissions is the installation of an SCR system prior to the air heater. SCR uses ammonia and a catalyst to reduce NOx to N_2 and H_2O. The SCR system consists of three subsystems: reactor vessel, ammonia storage and injection, and gas flow control. The SCR system is designed for 86 percent reduction with 2 ppmv ammonia slip at the end of the catalyst life. This, along with the low-NOx burners, achieves the emission limit of 0.07 lb/MMBtu.

The SCR capital costs are included with the boiler costs, as is the cost for the initial load of catalyst.

Selective non-catalytic reduction (SNCR) was considered for this application. However, with the installation of the low-NOx burners and overfire air system, the boiler exhaust gas contains relatively small amounts of NOx, which makes removal of the quantity of NOx with SNCR to reach the emissions limit of 0.07 lb/MMBtu difficult. SNCR works better in applications that contain medium to high quantities of NOx and require removal efficiencies in the range of 40 to 60 percent. SCR, because of the catalyst used in the reaction, can achieve higher efficiencies with lower concentrations of NOx.

SCR Operation Description

The reactor vessel is designed to allow proper retention time for the ammonia to contact the NOx in the boiler exhaust gas. Ammonia is injected into the gas immediately prior to entering the reactor vessel. The catalyst contained in the reactor vessel enhances the reaction between the ammonia and the NOx in the gas. Catalysts consist of various active materials such as titanium dioxide, vanadium pentoxide, and tungsten trioxide. The operating range for vanadium/titanium-based catalysts is 260°C (500°F) to 455°C (850°F). The boiler is equipped with economizer bypass to provide flue gas to the reactors at the desired temperature during periods of low flow rate, such as low load operation. Also included with the reactor vessel is soot-blowing equipment used for cleaning the catalyst.

The ammonia storage and injection system consists of the unloading facilities, bulk storage tank, vaporizers, dilution air skid, and injection grid.

The flue gas flow control consists of ductwork, dampers, and flow straightening devices required to route the boiler exhaust to the SCR reactor and then to the air heater. The economizer bypass and associated dampers for low load temperature control are also included.

4.1.4 PARTICULATE CONTROL

The fabric filter (or baghouse) consists of two separate single-stage, in-line, multi-compartment units. Each unit is of high (0.9-1.5 m/min [3-5 ft/min]) air-to-cloth ratio design with a pulse-jet on-line cleaning system. The ash is collected on the outside of the bags, which are supported by steel cages. The dust cake is removed by a pulse of compressed air. The bag material is polyphenylensulfide (PPS) with intrinsic Teflon (PTFE) coating [58]. The bags are rated for a continuous temperature of 180°C (356°F) and a peak temperature of 210°C (410°F). Each compartment contains a number of gas passages with filter bags, and heated ash hoppers supported by a rigid steel casing. The fabric filter is provided with necessary control devices, inlet gas distribution devices, insulators, inlet and outlet nozzles, expansion joints, and other items as required.

4.1.5 MERCURY REMOVAL

Mercury removal is based on a coal Hg content of 0.15 ppmd. The basis for the coal Hg concentration was discussed in Section 2.4. The combination of pollution control technologies used in the PC plants, SCR, fabric filters and FGD, result in significant co-benefit capture of mercury. The SCR promotes the oxidation of elemental mercury, which in turn enhances the mercury removal capability of the fabric filter and FGD unit. The mercury co-benefit capture is assumed to be 90 percent for this combination of control technologies as described in Section 2.4. Co-benefit capture alone is sufficient to meet current NSPS mercury limits so no activated carbon injection is included in the PC cases.

4.1.6 FLUE GAS DESULFURIZATION

The FGD system is a wet limestone forced oxidation positive pressure absorber non-reheat unit, with wet-stack, and gypsum production. The function of the FGD system is to scrub the boiler exhaust gases to remove the SO_2 prior to release to the environment, or entering into the Carbon Dioxide Removal (CDR) facility. Sulfur removal efficiency is 98 percent in the FGD unit for all cases. For Cases 10 and 12 with CO_2 capture, the SO_2 content of the scrubbed gases must be further reduced to approximately 10 ppmv to minimize formation of amine heat stable salts during the CO_2 absorption process. The CDR unit includes a polishing scrubber to reduce the flue gas SO_2 concentration from about 38 ppmv at the FGD exit to the required 10 ppmv prior to the CDR absorber. The scope of the FGD system is from the outlet of the ID fans to the stack inlet (Cases 9 and 11) or to the CDR process inlet (Cases 10 and 12). The system description is divided into three sections:

- Limestone Handling and Reagent Preparation
- FGD Scrubber

- Byproduct Dewatering

Reagent Preparation System

The function of the limestone reagent preparation system is to grind and slurry the limestone delivered to the plant. The scope of the system is from the day bin up to the limestone feed system. The system is designed to support continuous baseload operation.

Operation Description - Each day bin supplies a 100 percent capacity ball mill via a weigh feeder. The wet ball mill accepts the limestone and grinds the limestone to 90 to 95 percent passing 325 mesh (44 microns). Water is added at the inlet to the ball mill to create limestone slurry. The reduced limestone slurry is then discharged into a mill slurry tank. Mill recycle pumps, two per tank, pump the limestone water slurry to an assembly of hydrocyclones and distribution boxes. The slurry is classified into several streams, based on suspended solids content and size distribution.

The hydrocyclone underflow with oversized limestone is directed back to the mill for further grinding. The hydrocyclone overflow with correctly sized limestone is routed to a reagent storage tank. Reagent distribution pumps direct slurry from the tank to the absorber module.

FGD Scrubber

The flue gas exiting the air preheater section of the boiler passes through one of two parallel fabric filter units, then through the ID fans and into the one 100 percent capacity absorber module. The absorber module is designed to operate with counter-current flow of gas and reagent. Upon entering the bottom of the absorber vessel, the gas stream is subjected to an initial quenching spray of reagent. The gas flows upward through the spray zone, which provides enhanced contact between gas and reagent. Multiple spray elevations with header piping and nozzles maintain a consistent reagent concentration in the spray zone. Continuing upward, the reagent-laden gas passes through several levels of moisture separators. These consist of chevron-shaped vanes that direct the gas flow through several abrupt changes in direction, separating the entrained droplets of liquid by inertial effects. The scrubbed flue gas exits at the top of the absorber vessel and is routed to the plant stack or CDR process.

The scrubbing slurry falls to the lower portion of the absorber vessel, which contains a large inventory of liquid. Oxidation air is added to promote the oxidation of calcium sulfite contained in the slurry to calcium sulfate (gypsum). Multiple agitators operate continuously to prevent settling of solids and enhance mixture of the oxidation air and the slurry. Recirculation pumps recirculate the slurry from the lower portion of the absorber vessel to the spray level. Spare recirculation pumps are provided to ensure availability of the absorber.

The absorber chemical equilibrium is maintained by continuous makeup of fresh reagent, and blowdown of byproduct solids via the bleed pumps. A spare bleed pump is provided to ensure availability of the absorber. The byproduct solids are routed to the byproduct dewatering system. The circulating slurry is monitored for pH and density.

This FGD system is designed for wet stack operation. Scrubber bypass or reheat, which may be utilized at some older facilities to ensure the exhaust gas temperature is above the saturation temperature, is not employed in this reference plant design because new scrubbers have improved mist eliminator efficiency, and detailed flow modeling of the flue interior enables the placement of gutters and drains to intercept moisture that may be present and convey it to a drain. Consequently, raising the exhaust gas temperature above the FGD discharge temperature of 57°C (135°F) (non-CO_2 capture cases) or 32°C (89°F) (CO_2 capture cases) is not necessary.

Byproduct Dewatering

The function of the byproduct dewatering system is to dewater the bleed slurry from the FGD absorber modules. The dewatering process selected for this plant is gypsum dewatering producing wallboard grade gypsum. The scope of the system is from the bleed pump discharge connections to the gypsum storage pile.

Operation Description - The recirculating reagent in the FGD absorber vessel accumulates dissolved and suspended solids on a continuous basis as byproducts from the SO_2 absorption process. Maintenance of the quality of the recirculating slurry requires that a portion be withdrawn and replaced by fresh reagent. This is accomplished on a continuous basis by the bleed pumps pulling off byproduct solids and the reagent distribution pumps supplying fresh reagent to the absorber.

Gypsum (calcium sulfate) is produced by the injection of oxygen into the calcium sulfite produced in the absorber tower sump. The bleed from the absorber contains approximately 20 wt% gypsum. The absorber slurry is pumped by an absorber bleed pump to a primary dewatering hydrocyclone cluster. The primary hydrocyclone performs two process functions. The first function is to dewater the slurry from 20 wt% to 50 wt% solids. The second function of the primary hydrocyclone is to perform a $CaCO_3$ and $CaSO_4 \cdot 2H_2O$ separation. This process ensures a limestone stoichiometry in the absorber vessel of 1.10 and an overall limestone stoichiometry of 1.05. This system reduces the overall operating cost of the FGD system. The underflow from the hydrocyclone flows into the filter feed tank, from which it is pumped to a horizontal belt vacuum filter. Two 100 percent filter systems are provided for redundant capacity.

Hydrocyclones

The hydrocyclone is a simple and reliable device (no moving parts) designed to increase the slurry concentration in one step to approximately 50 wt%. This high slurry concentration is necessary to optimize operation of the vacuum belt filter.

The hydrocyclone feed enters tangentially and experiences centrifugal motion so that the heavy particles move toward the wall and flow out the bottom. Some of the lighter particles collect at the center of the cyclone and flow out the top. The underflow is thus concentrated from 20 wt% at the feed to 50 wt%.

Multiple hydrocyclones are used to process the bleed stream from the absorber. The hydrocyclones are configured in a cluster with a common feed header. The system has two hydrocyclone clusters, each with five 15 cm (6 inch) diameter units. Four cyclones are used to continuously process the bleed stream at design conditions, and one cyclone is spare.

Cyclone overflow and underflow are collected in separate launders. The overflow from the hydrocyclones still contains about 5 wt% solids, consisting of gypsum, fly ash, and limestone residues and is sent back to the absorber. The underflow of the hydrocyclones flows into the filter feed tank from where it is pumped to the horizontal belt vacuum filters.

Horizontal Vacuum Belt Filters

The secondary dewatering system consists of horizontal vacuum belt filters. The pre-concentrated gypsum slurry (50 wt%) is pumped to an overflow pan through which the slurry flows onto the vacuum belt. As the vacuum is pulled, a layer of cake is formed. The cake is dewatered to approximately 90 wt% solids as the belt travels to the discharge. At the discharge end of the filter, the filter cloth is turned over a roller where the solids are dislodged from the filter cloth. This cake falls through a chute onto the pile prior to the final byproduct uses. The required vacuum is provided by a vacuum pump. The filtrate is collected in a filtrate tank that provides surge volume for use of the filtrate in grinding the limestone. Filtrate that is not used for limestone slurry preparation is returned to the absorber.

4.1.7 CARBON DIOXIDE RECOVERY FACILITY

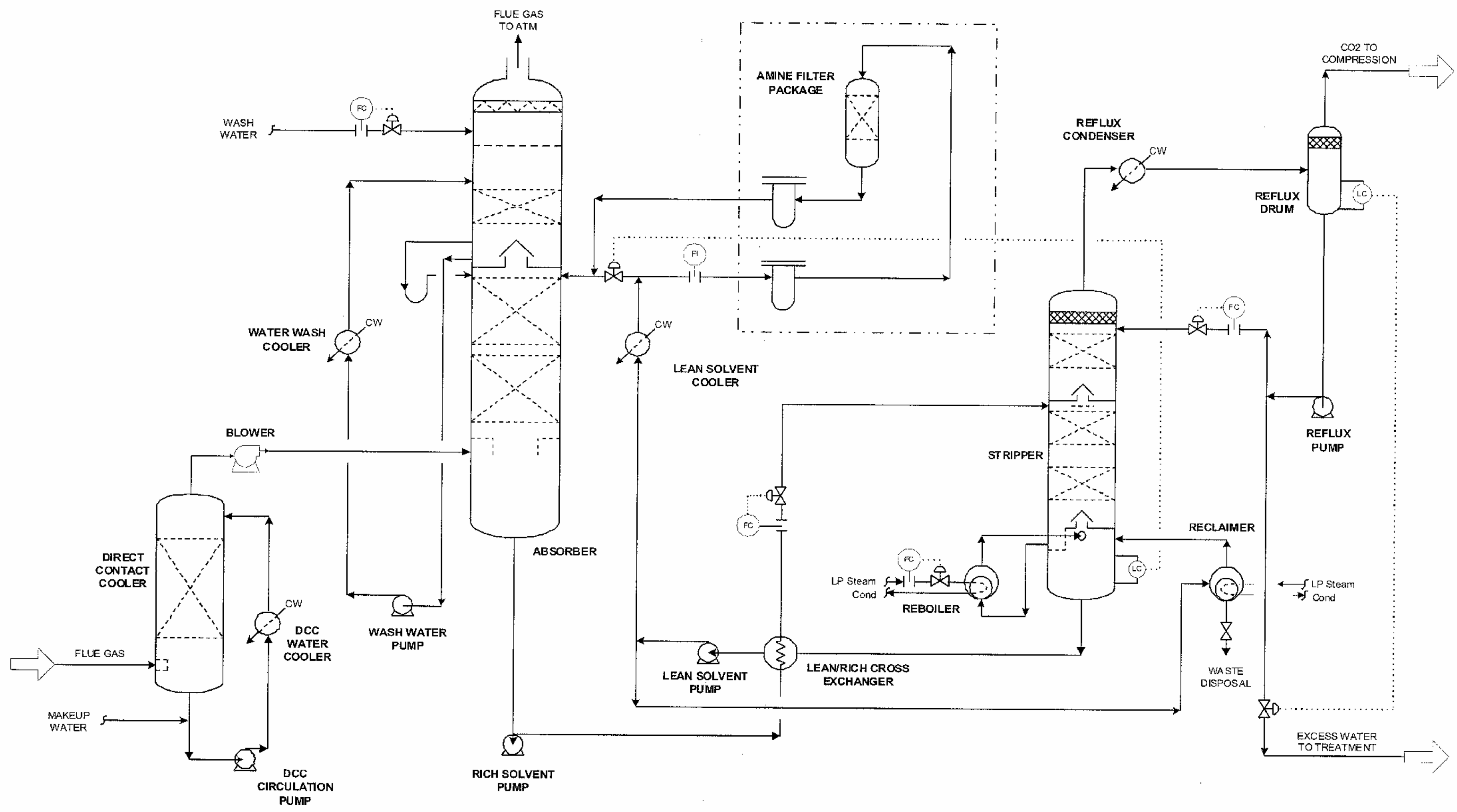
A Carbon Dioxide Recovery (CDR) facility is used in Cases 10 and 12 to remove 90 percent of the CO_2 in the flue gas exiting the FGD unit, purify it, and compress it to a supercritical condition. The flue gas exiting the FGD unit contains about 1 percent more CO_2 than the raw flue gas because of the CO_2 liberated from the limestone in the FGD absorber vessel. The CDR is comprised of the flue gas supply, SO_2 polishing, CO_2 absorption, solvent stripping and reclaiming, and CO_2 compression and drying.

The CO_2 absorption/stripping/solvent reclaim process for Cases 10 and 12 is based on the Fluor Econamine FG Plus technology. [59] A typical flowsheet is shown in Exhibit 4-1. The Econamine FG Plus process uses a formulation of monoethanolamine (MEA) and a proprietary inhibitor to recover CO_2 from the flue gas. This process is designed to recover high-purity CO_2 from low-pressure streams that contain oxygen, such as flue gas from coal-fired power plants, gas turbine exhaust gas, and other waste gases. The Econamine process used in this study differs from previous studies, including the 2004 IEA study, [59] in the following ways:

- The complexity of the control and operation of the plant is significantly decreased
- Solvent consumption is decreased
- Hard to dispose waste from the plant is eliminated

The above are achieved at the expense of a slightly higher steam requirement in the stripper (3,556 kJ/kg [1,530 Btu/lb] versus 3,242 kJ/kg [1,395 Btu/lb] used in the IEA study). [60]

Exhibit 4-1 Fluor Econamine FG Plus Typical Flow Diagram



SO_2 Polishing and Flue Gas Cooling and Supply

To prevent the accumulation of heat stable salts, the incoming flue gas must have an SO_2 concentration of 10 ppmv or less. The gas exiting the FGD system passes through an SO_2 polishing step to achieve this objective. The polishing step consists of a non-plugging, low-differential-pressure, spray-baffle-type scrubber using a 20 wt% solution of sodium hydroxide (NaOH). A removal efficiency of about 75 percent is necessary to reduce SO_2 emissions from the FGD outlet to 10 ppmv as required by the Econamine process. The polishing scrubber proposed for this application has been demonstrated in numerous industrial applications throughout the world and can achieve removal efficiencies of over 95 percent if necessary.

The polishing scrubber also serves as the flue gas cooling system. Cooling water from the PC plant is used to reduce the temperature and hence moisture content of the saturated flue gas exiting the FGD system. Flue gas is cooled beyond the CO_2 absorption process requirements to 32°C (90°F) to account for the subsequent flue gas temperature increase of about 17°C (30°F) in the flue gas blower. Downstream from the Polishing Scrubber flue gas pressure is boosted in the Flue Gas Blowers by approximately 0.014 MPa (2 psi) to overcome pressure drop in the CO_2 absorber tower.

Circulating Water System

Cooling water is provided from the PC plant circulating water system and returned to the PC plant cooling tower. The CDR facility requires a significant amount of cooling water for flue gas cooling, water wash cooling, absorber intercooling, reflux condenser duty, reclaimer cooling, the lean solvent cooler, and CO_2 compression interstage cooling. The cooling water requirements for the CDR facility in the two PC capture cases range from 1,514,180-1,703,450 lpm (400,000-450,000 gpm), which greatly exceeds the PC plant cooling water requirement of 719,235-870,650 lpm (190,000-230,000 gpm).

CO_2 Absorption

The cooled flue gas enters the bottom of the CO_2 Absorber and flows up through the tower countercurrent to a stream of lean MEA-based solvent called Econamine FG Plus. Approximately 90 percent of the CO_2 in the feed gas is absorbed into the lean solvent, and the rest leaves the top of the absorber section and flows into the water wash section of the tower. The lean solvent enters the top of the absorber, absorbs the CO_2 from the flue gases and leaves the bottom of the absorber with the absorbed CO_2.

Water Wash Section

The purpose of the Water Wash section is to minimize solvent losses due to mechanical entrainment and evaporation. The flue gas from the top of the CO_2 Absorption section is contacted with a re-circulating stream of water for the removal of most of the lean solvent. The scrubbed gases, along with unrecovered solvent, exit the top of the wash section for discharge to the atmosphere via the vent stack. The water stream from the bottom of the wash section is collected on a chimney tray. A portion of the water collected on the chimney tray spills over to the absorber section as water makeup for the amine with the remainder pumped via the Wash Water Pump and cooled by the Wash Water Cooler, and recirculated to the top of the CO_2

Absorber. The wash water level is maintained by water makeup from the Wash Water Makeup Pump.

Rich/Lean Amine Heat Exchange System

The rich solvent from the bottom of the CO_2 Absorber is preheated by the lean solvent from the Solvent Stripper in the Rich Lean Solvent Exchanger. The heated rich solvent is routed to the Solvent Stripper for removal of the absorbed CO_2. The stripped solvent from the bottom of the Solvent Stripper is pumped via the Hot Lean Solvent Pumps through the Rich Lean Exchanger to the Solvent Surge Tank. Prior to entering the Solvent Surge Tank, a slipstream of the lean solvent is pumped via the Solvent Filter Feed Pump through the Solvent Filter Package to prevent buildup of contaminants in the solution. From the Solvent Surge Tank the lean solvent is pumped via the Warm Lean Solvent Pumps to the Lean Solvent Cooler for further cooling, after which the cooled lean solvent is returned to the CO_2 Absorber, completing the circulating solvent circuit.

Solvent Stripper

The purpose of the Solvent Stripper is to separate the CO_2 from the rich solvent feed exiting the bottom of the CO_2 Absorber. The rich solvent is collected on a chimney tray below the bottom packed section of the Solvent Stripper and routed to the Solvent Stripper Reboilers where the rich solvent is heated by steam, stripping the CO_2 from the solution. Steam is provided from the LP section of the steam turbine and is between 0.9-1.2 MPa (130-170 psia) and 366-396°C (690-745°F) for the two PC cases. The hot wet vapor from the top of the stripper containing CO_2, steam, and solvent vapor, is partially condensed in the Solvent Stripper Condenser by cross exchanging the hot wet vapor with cooling water. The partially condensed stream then flows to the Solvent Stripper Reflux Drum where the vapor and liquid are separated. The uncondensed CO_2-rich gas is then delivered to the CO_2 product compressor. The condensed liquid from the Solvent Stripper Reflux Drum is pumped via the Solvent Stripper Reflux Pumps where a portion of condensed overhead liquid is used as make-up water for the Water Wash section of the CO_2 Absorber. The rest of the pumped liquid is routed back to the Solvent Stripper as reflux, which aids in limiting the amount of solvent vapors entering the stripper overhead system.

Solvent Stripper Reclaimer

A small slipstream of the lean solvent from the Solvent Stripper bottoms is fed to the Solvent Stripper Reclaimer for the removal of high-boiling nonvolatile impurities (heat stable salts - HSS), volatile acids and iron products from the circulating solvent solution. The solvent bound in the HSS is recovered by reaction with caustic and heating with steam. The solvent reclaimer system reduces corrosion, foaming and fouling in the solvent system. The reclaimed solvent is returned to the Solvent Stripper and the spent solvent is pumped via the Solvent Reclaimer Drain Pump to the Solvent Reclaimer Drain Tank.

Steam Condensate

Steam condensate from the Solvent Stripper Reclaimer accumulates in the Solvent Reclaimer Condensate Drum and is level controlled to the Solvent Reboiler Condensate Drum. Steam condensate from the Solvent Stripper Reboilers is also collected in the Solvent Reboiler Condensate Drum and returned to the the steam cycle between boiler feedwater heaters 4 and 5 via the Solvent Reboiler Condensate Pumps.

Corrosion Inhibitor System

A proprietary corrosion inhibitor is continuously injected into the CO_2 Absorber rich solvent bottoms outlet line, the Solvent Stripper bottoms outlet line and the Solvent Stripper top tray. This constant injection is to help control the rate of corrosion throughout the CO_2 recovery plant system.

Gas Compression and Drying System

In the compression section, the CO_2 is compressed to 15.3 MPa (2,215 psia) by a six-stage centrifugal compressor. The discharge pressures of the stages were balanced to give reasonable power distribution and discharge temperatures across the various stages as shown in Exhibit 4-2.

Exhibit 4-2 CO_2 Compressor Interstage Pressures

Stage	Outlet Pressure, MPa (psia)
1	0.36 (52)
2	0.78 (113)
3	1.71 (248)
4	3.76 (545)
5	8.27 (1,200)
6	15.3 (2,215)

Power consumption for this large compressor was estimated assuming an isentropic efficiency of 84 percent. During compression to 15.3 MPa (2,215 psia) in the multiple-stage, intercooled compressor, the CO_2 stream is dehydrated to a dewpoint of -40ºC (-40°F) with triethylene glycol. The virtually moisture-free supercritical CO_2 stream is delivered to the plant battery limit as sequestration ready. CO_2 TS&M costs were estimated and included in LCOE using the methodology described in Section 2.7.

4.1.8 <u>Power Generation</u>

The steam turbine is designed for long-term operation (90 days or more) at MCR with throttle control valves 95 percent open. It is also capable of a short-term 5 percent OP/VWO condition (16 hours).

For the subcritical cases, the steam turbine is a tandem compound type, consisting of HP-IP-two LP (double flow) sections enclosed in three casings, designed for condensing single reheat operation, and equipped with non-automatic extractions and four-flow exhaust. The turbine drives a hydrogen-cooled generator. The turbine has DC motor-operated lube oil pumps, and main lube oil pumps, which are driven off the turbine shaft [61]. The exhaust pressure is 50.8 cm

(2 in) Hg in the single pressure condenser. There are seven extraction points. The condenser is two-shell, transverse, single pressure with divided waterbox for each shell.

The steam-turbine generator systems for the supercritical plants are similar in design to the subcritical systems. The differences include steam cycle conditions and eight extractions points versus seven for the subcritical design.

Turbine bearings are lubricated by a closed-loop, water-cooled pressurized oil system. Turbine shafts are sealed against air in-leakage or steam blowout using a labyrinth gland arrangement connected to a low-pressure steam seal system. The generator stator is cooled with a closed-loop water system consisting of circulating pumps, shell and tube or plate and frame type heat exchangers, filters, and deionizers, all skid-mounted. The generator rotor is cooled with a hydrogen gas recirculation system using fans mounted on the generator rotor shaft.

Operation Description - The turbine stop valves, control valves, reheat stop valves, and intercept valves are controlled by an electro-hydraulic control system. Main steam from the boiler passes through the stop valves and control valves and enters the turbine at 16.5 MPa/566°C (2400 psig/1050ºF) for the subcritical cases and 24.1MPa /593°C (3500psig/1100°F) for the supercritical cases. The steam initially enters the turbine near the middle of the high-pressure span, flows through the turbine, and returns to the boiler for reheating. The reheat steam flows through the reheat stop valves and intercept valves and enters the IP section at 566°C (1050ºF) in the subcritical cases and 593°C (1100°F) in the supercritical cases. After passing through the IP section, the steam enters a crossover pipe, which transports the steam to the two LP sections. The steam divides into four paths and flows through the LP sections exhausting downward into the condenser.

The turbine is designed to operate at constant inlet steam pressure over the entire load range.

4.1.9 BALANCE OF PLANT

The balance of plant components consist of the condensate, feedwater, main and reheat steam, extraction steam, ash handling, ducting and stack, waste treatment and miscellaneous systems as described below.

Condensate

The function of the condensate system is to pump condensate from the condenser hotwell to the deaerator, through the gland steam condenser and the LP feedwater heaters. Each system consists of one main condenser; two variable speed electric motor-driven vertical condensate pumps each sized for 50 percent capacity; one gland steam condenser; four LP heaters; and one deaerator with storage tank.

Condensate is delivered to a common discharge header through two separate pump discharge lines, each with a check valve and a gate valve. A common minimum flow recirculation line discharging to the condenser is provided downstream of the gland steam condenser to maintain minimum flow requirements for the gland steam condenser and the condensate pumps.

LP feedwater heaters 1 through 4 are 50 percent capacity, parallel flow, and are located in the condenser neck. All remaining feedwater heaters are 100 percent capacity shell and U-tube heat exchangers. Each LP feedwater heater is provided with inlet/outlet isolation valves and a full capacity bypass. LP feedwater heater drains cascade down to the next lowest extraction pressure heater and finally discharge into the condenser. Pneumatic level control valves control normal drain levels in the heaters. High heater level dump lines discharging to the condenser are provided for each heater for turbine water induction protection. Pneumatic level control valves control dump line flow.

Feedwater

The function of the feedwater system is to pump the feedwater from the deaerator storage tank through the HP feedwater heaters to the economizer. One turbine-driven boiler feedwater pump sized at 100 percent capacity is provided to pump feedwater through the HP feedwater heaters. One 25 percent motor-driven boiler feedwater pump is provided for startup. The pumps are provided with inlet and outlet isolation valves, and individual minimum flow recirculation lines discharging back to the deaerator storage tank. The recirculation flow is controlled by automatic recirculation valves, which are a combination check valve in the main line and in the bypass, bypass control valve, and flow sensing element. The suction of the boiler feed pump is equipped with startup strainers, which are utilized during initial startup and following major outages or system maintenance.

Each HP feedwater heater is provided with inlet/outlet isolation valves and a full capacity bypass. Feedwater heater drains cascade down to the next lowest extraction pressure heater and finally discharge into the deaerator. Pneumatic level control valves control normal drain level in the heaters. High heater level dump lines discharging to the condenser are provided for each heater for turbine water induction protection. Dump line flow is controlled by pneumatic level control valves.

The deaerator is a horizontal, spray tray type with internal direct contact stainless steel vent condenser and storage tank. The boiler feed pump turbine is driven by main steam up to 60 percent plant load. Above 60 percent load, extraction from the IP turbine exhaust (1.05 MPa/395°C [153 psig/743°F]) provides steam to the boiler feed pump steam turbine.

Main and Reheat Steam

The function of the main steam system is to convey main steam from the boiler superheater outlet to the HP turbine stop valves. The function of the reheat system is to convey steam from the HP turbine exhaust to the boiler reheater and from the boiler reheater outlet to the IP turbine stop valves.

Main steam exits the boiler superheater through a motor-operated stop/check valve and a motor-operated gate valve and is routed in a single line feeding the HP turbine. A branch line off the IP turbine exhaust feeds the boiler feed water pump turbine during unit operation starting at approximately 60 percent load.

Cold reheat steam exits the HP turbine, flows through a motor-operated isolation gate valve and a flow control valve, and enters the boiler reheater. Hot reheat steam exits the boiler reheater through a motor-operated gate valve and is routed to the IP turbine. A branch connection from the cold reheat piping supplies steam to feedwater heater 7.

Extraction Steam

The function of the extraction steam system is to convey steam from turbine extraction points through the following routes:

- From HP turbine exhaust (cold reheat) to heater 7
- From IP turbine extraction to heater 6 and the deaerator (heater 5)
- From LP turbine extraction to heaters 1, 2, 3, and 4

The turbine is protected from overspeed on turbine trip, from flash steam reverse flow from the heaters through the extraction piping to the turbine. This protection is provided by positive closing, balanced disc non-return valves located in all extraction lines except the lines to the LP feedwater heaters in the condenser neck. The extraction non-return valves are located only in horizontal runs of piping and as close to the turbine as possible.

The turbine trip signal automatically trips the non-return valves through relay dumps. The remote manual control for each heater level control system is used to release the non-return valves to normal check valve service when required to restart the system.

Circulating Water System

It is assumed that the plant is serviced by a public water facility and has access to groundwater for use as makeup cooling water with minimal pretreatment. All filtration and treatment of the circulating water are conducted on site. A mechanical draft, wood frame, counter-flow cooling tower is provided for the circulating water heat sink. Two 50 percent circulating water pumps are provided. The circulating water system provides cooling water to the condenser, the auxiliary cooling water system, and the CDR facility in capture cases.

The auxiliary cooling water system is a closed-loop system. Plate and frame heat exchangers with circulating water as the cooling medium are provided. This system provides cooling water to the lube oil coolers, turbine generator, boiler feed pumps, etc. All pumps, vacuum breakers, air release valves, instruments, controls, etc. are included for a complete operable system.

The CDR system in Cases 10 and 12 requires a substantial amount of cooling water that is provided by the PC plant circulating water system. The additional cooling load imposed by the CDR is reflected in the significantly larger circulating water pumps and cooling tower in those cases.

Ash Handling System

The function of the ash handling system is to provide the equipment required for conveying, preparing, storing, and disposing of the fly ash and bottom ash produced on a daily basis by the boiler. The scope of the system is from the baghouse hoppers, air heater and economizer hopper collectors, and bottom ash hoppers to the hydrobins (for bottom ash) and truck filling stations (for fly ash). The system is designed to support short-term operation at the 5 percent OP/VWO condition (16 hours) and long-term operation at the 100 percent guarantee point (90 days or more).

The fly ash collected in the baghouse and the air heaters is conveyed to the fly ash storage silo. A pneumatic transport system using low-pressure air from a blower provides the transport mechanism for the fly ash. Fly ash is discharged through a wet unloader, which conditions the fly ash and conveys it through a telescopic unloading chute into a truck for disposal.

The bottom ash from the boiler is fed into a clinker grinder. The clinker grinder is provided to break up any clinkers that may form. From the clinker grinders the bottom ash is sluiced to hydrobins for dewatering and offsite removal by truck.

Ash from the economizer hoppers and pyrites (rejected from the coal pulverizers) is conveyed using water to the economizer/pyrites transfer tank. This material is then sluiced on a periodic basis to the hydrobins.

Ducting and Stack

One stack is provided with a single fiberglass-reinforced plastic (FRP) liner. The stack is constructed of reinforced concrete. The stack is 152 m (500 ft) high for adequate particulate dispersion.

Waste Treatment/Miscellaneous Systems

An onsite water treatment facility treats all runoff, cleaning wastes, blowdown, and backwash to within the U.S. EPA standards for suspended solids, oil and grease, pH, and miscellaneous metals. Waste treatment equipment is housed in a separate building. The waste treatment system consists of a water collection basin, three raw waste pumps, an acid neutralization system, an oxidation system, flocculation, clarification/thickening, and sludge dewatering. The water collection basin is a synthetic-membrane-lined earthen basin, which collects rainfall runoff, maintenance cleaning wastes, and backwash flows.

The raw waste is pumped to the treatment system at a controlled rate by the raw waste pumps. The neutralization system neutralizes the acidic wastewater with hydrated lime in a two-stage system, consisting of a lime storage silo/lime slurry makeup system, dry lime feeder, lime slurry tank, slurry tank mixer, and lime slurry feed pumps.

The oxidation system consists of an air compressor, which injects air through a sparger pipe into the second-stage neutralization tank. The flocculation tank is fiberglass with a variable speed agitator. A polymer dilution and feed system is also provided for flocculation. The clarifier is a plate-type, with the sludge pumped to the dewatering system. The sludge is dewatered in filter presses and disposed offsite. Trucking and disposal costs are included in the cost estimate. The filtrate from the sludge dewatering is returned to the raw waste sump.

Miscellaneous systems consisting of fuel oil, service air, instrument air, and service water are provided. A storage tank provides a supply of No. 2 fuel oil used for startup and for a small auxiliary boiler. Fuel oil is delivered by truck. All truck roadways and unloading stations inside the fence area are provided.

Buildings and Structures

Foundations are provided for the support structures, pumps, tanks, and other plant components. The following buildings are included in the design basis:

- Steam turbine building
- Boiler building
- Administration and service building
- Makeup water and pretreatment building
- Fuel oil pump house
- Coal crusher building
- Continuous emissions monitoring building
- Pump house and electrical equipment building
- Guard house
- Runoff water pump house
- Industrial waste treatment building
- FGD system buildings

4.1.10 ACCESSORY ELECTRIC PLANT

The accessory electric plant consists of switchgear and control equipment, generator equipment, station service equipment, conduit and cable trays, and wire and cable. It also includes the main power transformer, required foundations, and standby equipment.

4.1.11 INSTRUMENTATION AND CONTROL

An integrated plant-wide control and monitoring DCS is provided. The DCS is a redundant microprocessor-based, functionally distributed system. The control room houses an array of multiple video monitor and keyboard units. The monitor/keyboard units are the primary interface between the generating process and operations personnel. The DCS incorporates plant monitoring and control functions for all the major plant equipment. The DCS is designed to provide 99.5 percent availability. The plant equipment and the DCS are designed for automatic response to load changes from minimum load to 100 percent. Startup and shutdown routines are implemented as supervised manual, with operator selection of modular automation routines available.

4.2 SUBCRITICAL PC CASES

This section contains an evalution of plant designs for Cases 9 and 10 which are based on a subcritical PC plant with a nominal net output of 550 MWe. Both plants use a single reheat 16.5 MPa/566°C/566°C (2400 psig/1050°F/1050°F) cycle. The only difference between the two plants is that Case 10 includes CO_2 capture while Case 9 does not.

The balance of Section 4.2 is organized as follows:

- Process and System Description provides an overview of the technology operation as applied to Case 9. The systems that are common to all PC cases were covered in Section 4.1 and only features that are unique to Case 9 are discussed further in this section.
- Key Assumptions is a summary of study and modeling assumptions relevant to Cases 9 and 10.
- Sparing Philosophy is provided for both Cases 9 and 10.
- Performance Results provides the main modeling results from Case 9, including the performance summary, environmental performance, water balance, mass and energy balance diagrams and energy balance table.
- Equipment List provides an itemized list of major equipment for Case 9 with account codes that correspond to the cost accounts in the Cost Estimates section.
- Cost Estimates provides a summary of capital and operating costs for Case 9.
- Process and System Description, Performance Results, Equipment List and Cost Estimates are discussed for Case 10.

4.2.1 PROCESS DESCRIPTION

In this section the subcritical PC process without CO_2 capture is described. The system description follows the block flow diagram (BFD) in Exhibit 4-3 and stream numbers reference the same Exhibit. The tables in Exhibit 4-4 provide process data for the numbered streams in the BFD.

Coal (stream 6) and primary air (stream 4) are introduced into the boiler through the wall-fired burners. Additional combustion air, including the overfire air, is provided by the forced draft fans (stream 2). The boiler operates at a slight negative pressure so air leakage is into the boiler, and the infiltration air is accounted for in stream 5.

Flue gas exits the boiler through the SCR reactor (stream 8) and is cooled to 177°C (350°F) in the combustion air preheater (not shown) before passing through a fabric filter for particulate removal (stream 10). An ID fan increases the flue gas temperature to 188°C (370°F) and provides the motive force for the flue gas (stream 11) to pass through the FGD unit. FGD inputs and outputs include makeup water (stream 13), oxidation air (stream 14), limestone slurry (stream 12) and product gypsum (stream 15). The clean, saturated flue gas exiting the FGD unit (stream 16) passes to the plant stack and is discharged to atmosphere.

Exhibit 4-3 Case 9 Process Flow Diagram, Subcritical Unit without CO_2 Capture

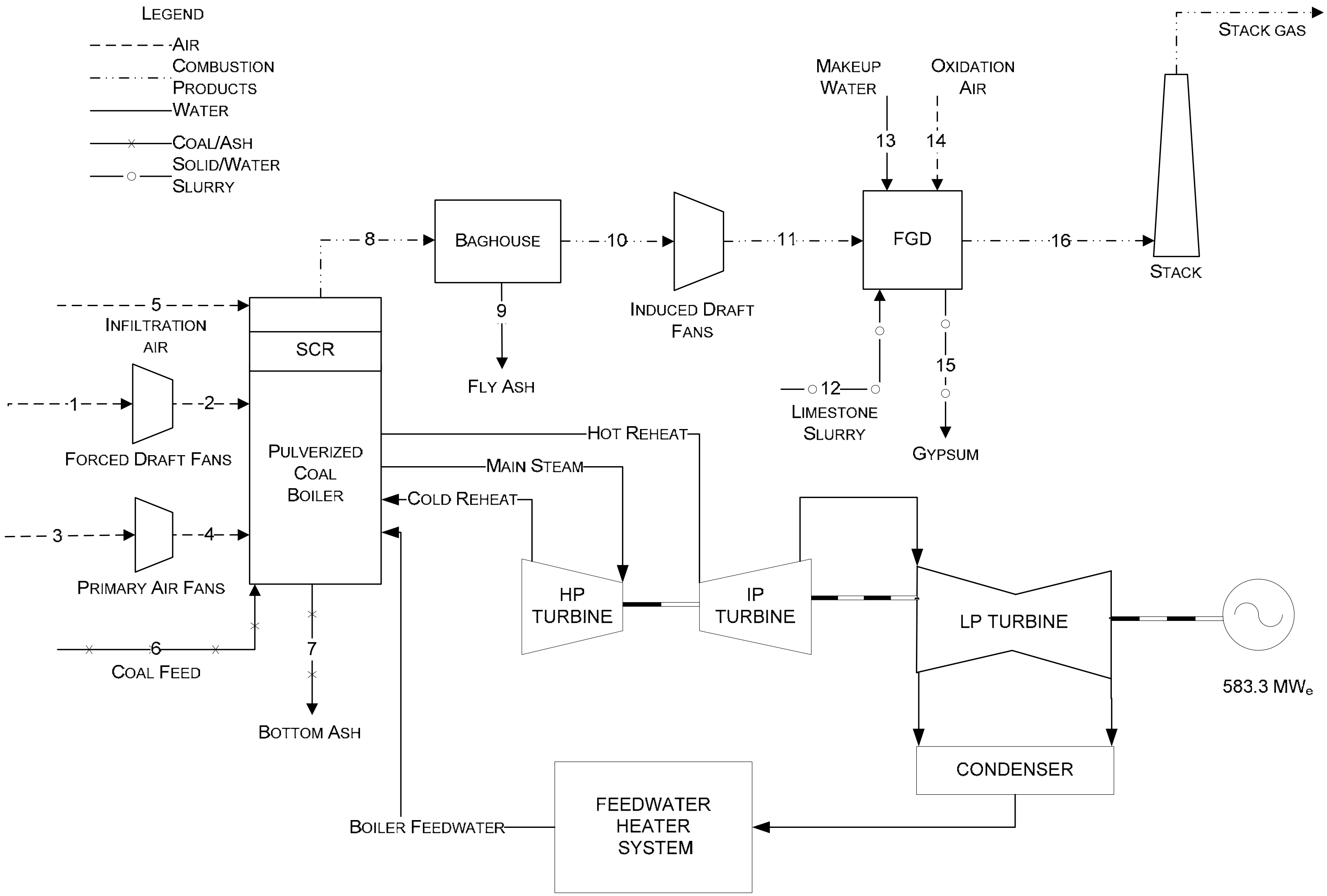


Exhibit 4-4 Case 9 Stream Table, Subcritical Unit without CO_2 Capture

	1	2	3	4	5	6	7	8
V-L Mole Fraction								
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0087
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.1450
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	0.0870
N_2	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.7324
O_2	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0247
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021
Total	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000
V-L Flow (lb_{mol}/hr)	114,117	114,117	35,055	35,055	2,636	0	0	160,576
V-L Flow (lb/hr)	3,293,060	3,293,060	1,011,590	1,011,590	76,071	0	0	4,775,980
Solids Flowrate	0	0	0	0	0	437,699	8,489	33,954
Temperature (°F)	59	66	59	78	59	78	350	350
Pressure (psia)	14.70	15.25	14.70	16.14	14.70	14.70	14.40	14.40
Enthalpy (BTU/lb)^A	13.1	14.9	13.1	17.7	13.1	11,676	51.4	135.7
Density (lb/ft^3)	0.08	0.08	0.08	0.08	0.08	--	--	0.05
Avg. Molecular Weight	28.86	28.86	28.86	28.86	28.86	--	--	29.74

	9	10	11	12	13	14	15	16
V-L Mole Fraction								
Ar	0.0000	0.0087	0.0087	0.0000	0.0000	0.0092	0.0000	0.0079
CO_2	0.0000	0.1450	0.1450	0.0000	0.0000	0.0003	0.0014	0.1317
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0000	0.0870	0.0870	1.0000	1.0000	0.0099	0.9978	0.1725
N_2	0.0000	0.7324	0.7324	0.0000	0.0000	0.7732	0.0007	0.6644
O_2	0.0000	0.0247	0.0247	0.0000	0.0000	0.2074	0.0000	0.0234
SO_2	0.0000	0.0021	0.0021	0.0000	0.0000	0.0000	0.0000	0.0000
Total	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flow (lb_{mol}/hr)	0	160,576	160,576	5,701	26,948	1,901	15,077	179,211
V-L Flow (lb/hr)	0	4,775,980	4,775,980	102,702	485,483	54,846	272,302	5,122,540
Solids Flowrate	33,954	0	0	43,585	0	0	67,754	0
Temperature (°F)	350	350	370	59	59	59	135	135
Pressure (psia)	14.20	14.20	15.26	14.70	14.70	14.70	14.70	14.70
Enthalpy (BTU/lb)^A	51.4	136.3	141.5	--	32.4	13.1	88.0	139.1
Density (lb/ft^3)	--	0.05	0.05	62.62	62.62	0.08	39.65	0.07
Avg. Molecular Weight	--	29.74	29.74	18.02	18.02	28.86	18.06	28.58

A - Reference conditions are 32.02 F & 0.089 PSIA

4.2.2 KEY SYSTEM ASSUMPTIONS

System assumptions for Cases 9 and 10, subcritical PC with and without CO_2 capture, are compiled in Exhibit 4-5.

Exhibit 4-5 Subcritical PC Plant Study Configuration Matrix

	Case 9 w/o CO_2 Capture	Case 10 w/CO_2 Capture
Steam Cycle, MPa/°C/°C (psig/°F/°F)	16.5/566/566 (2400/1050/1050)	16.5/566/566 (2400/1050/1050)
Coal	Illinois No. 6	Illinois No. 6
Condenser pressure, mm Hg (in Hg)	50.8 (2)	50.8 (2)
Boiler Efficiency, %	89	89
Cooling water to condenser, °C (ºF)	16 (60)	16 (60)
Cooling water from condenser, °C (ºF)	27 (80)	27 (80)
Stack temperature, °C (°F)	57 (135)	32 (89)
SO_2 Control	Wet Limestone Forced Oxidation	Wet Limestone Forced Oxidation
FGD Efficiency, % (A)	98	98 (B, C)
NOx Control	LNB w/OFA and SCR	LNB w/OFA and SCR
SCR Efficiency, % (A)	86	86
Ammonia Slip (end of catalyst life), ppmv	2	2
Particulate Control	Fabric Filter	Fabric Filter
Fabric Filter efficiency, % (A)	99.8	99.8
Ash Distribution, Fly/Bottom	80% / 20%	80% / 20%
Mercury Control	Co-benefit Capture	Co-benefit Capture
Mercury removal efficiency, % (A)	90	90
CO_2 Control	N/A	Econamine FG Plus
CO_2 Capture, % (A)	N/A	90
CO_2 Sequestration	N/A	Off-site Saline Formation

A. Removal efficiencies are based on the flue gas content
B. An SO_2 polishing step is included to meet more stringent SOx content limits in the flue gas (< 10 ppmv) to reduce formation of amine heat stable salts during the CO_2 absorption process
C. SO_2 exiting the post-FGD polishing step is absorbed in the CO_2 capture process making stack emissions negligible

Balance of Plant – Cases 9 and 10

The balance of plant assumptions are common to all cases and are presented in Exhibit 4-6.

Exhibit 4-6 Balance of Plant Assumptions

Cooling system	Recirculating Wet Cooling Tower
Fuel and Other storage	
Coal	30 days
Ash	30 days
Gypsum	30 days
Limestone	30 days
Plant Distribution Voltage	
Motors below 1 hp	110/220 volt
Motors between 1 hp and 250 hp	480 volt
Motors between 250 hp and 5,000 hp	4,160 volt
Motors above 5,000 hp	13,800 volt
Steam and Gas Turbine generators	24,000 volt
Grid Interconnection voltage	345 kV
Water and Waste Water	
Makeup Water	The water supply is 50 percent from a local Publicly Owned Treatment Works (POTW) and 50 percent from groundwater, and is assumed to be in sufficient quantities to meet plant makeup requirements. Makeup for potable, process, and de-ionized (DI) water is drawn from municipal sources.
Process Wastewater	Storm water that contacts equipment surfaces is collected and treated for discharge through a permitted discharge.
Sanitary Waste Disposal	Design includes a packaged domestic sewage treatment plant with effluent discharged to the industrial wastewater treatment system. Sludge is hauled off site. Packaged plant is sized for 5.68 cubic meters per day (1,500 gallons per day)
Water Discharge	Most of the process wastewater is recycled to the cooling tower basin. Blowdown will be treated for chloride and metals, and discharged.

4.2.3 SPARING PHILOSOPHY

Single trains are used throughout the design with exceptions where equipment capacity requires an additional train. There is no redundancy other than normal sparing of rotating equipment. The plant design consists of the following major subsystems:

- One dry-bottom, wall-fired PC subcritical boiler (1 x 100%)
- Two SCR reactors (2 x 50%)
- Two single-stage, in-line, multi-compartment fabric filters (2 x 50%)
- One wet limestone forced oxidation positive pressure absorber (1 x 100%)
- One steam turbine (1 x 100%)
- For Case 10 only, two parallel Econamine FG Plus CO_2 absorption systems, with each system consisting of two absorbers, strippers and ancillary equipment (2 x 50%)

4.2.4 CASE 9 PERFORMANCE RESULTS

The plant produces a net output of 550 MWe at a net plant efficiency of 36.8 percent (HHV basis).

Overall performance for the plant is summarized in Exhibit 4-7 which includes auxiliary power requirements.

Exhibit 4-7 Case 9 Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
TOTAL (STEAM TURBINE) POWER, kWe	**583,315**
AUXILIARY LOAD SUMMARY, kWe (Note 1)	
Coal Handling and Conveying	420
Limestone Handling & Reagent Preparation	950
Pulverizers	2,980
Ash Handling	570
Primary Air Fans	1,390
Forced Draft Fans	1,770
Induced Draft Fans	7,590
SCR	60
Baghouse	100
FGD Pumps and Agitators	3,170
Amine System Auxiliaries	N/A
CO_2 Compression	N/A
Condensate Pumps	1,390
Miscellaneous Balance of Plant (Note 2)	2,000
Steam Turbine Auxiliaries	400
Circulating Water Pumps	5,440
Cooling Tower Fans	2,810
Transformer Loss	1,830
TOTAL AUXILIARIES, kWe	**32,870**
NET POWER, kWe	**550,445**
Net Plant Efficiency (HHV)	36.8%
Net Plant Heat Rate (Btu/kWh)	9,276
CONDENSER COOLING DUTY 10^6 kJ/h (10^6 Btu/h)	2,656 (2,520)
CONSUMABLES	
As-Received Coal Feed, kg/h (lb/h)	198,537 (437,699)
Limestone Sorbent Feed, kg/h (lb/h)	19,770 (43,585)
Thermal Input, kWt	1,496,479
Makeup water, m^3/min (gpm)	23.5 (6,212)

Notes:
1. Boiler feed pumps are steam turbine driven
2. Includes plant control systems, lighting, HVAC and miscellanous low voltage loads

Environmental Performance

The environmental targets for emissions of Hg, NOx, SO_2 and particulate matter were presented in Section 2.4. A summary of the plant air emissions for Case 9 is presented in Exhibit 4-8.

Exhibit 4-8 Case 9 Air Emissions

	kg/GJ ($lb/10^6$ Btu)	Tonne/year (ton/year) 85% capacity factor	kg/MWh (lb/MWh)
SO_2	0.037 (0.085)	1,463 (1,613)	0.337 (0.743)
NO_X	0.030 (0.070)	1,331 (1,207)	0.278 (0.613)
Particulates	0.006 (0.013)	224 (247)	0.052 (0.114)
Hg	0.49×10^{-6} (1.14×10^{-6})	0.020 (0.022)	4.5×10^{-6} (10.0×10^{-6})
CO_2	87.5 (203)	3,506,000 (3,865,000)	807 (1,780)
CO_2[1]			855 (1,886)

[1] CO_2 emissions based on net power instead of gross power

SO_2 emissions are controlled using a wet limestone forced oxidation scrubber that achieves a removal efficiency of 98 percent. The byproduct calcium sulfate is dewatered and stored on site. The wallboard grade material can potentially be marketed and sold, but since it is highly dependent on local market conditions, no byproduct credit was taken. The saturated flue gas exiting the scrubber is vented through the plant stack.

NOx emissions are controlled to about 0.5 $lb/10^6$ Btu through the use of LNBs and OFA. An SCR unit then further reduces the NOx concentration by 86 percent to 0.07 $lb/10^6$ Btu.

Particulate emissions are controlled using a pulse jet fabric filter which operates at an efficiency of 99.8 percent.

Co-benefit capture results in a 90 percent reduction of mercury emissions. CO_2 emissions represent the uncontrolled discharge from the process.

Exhibit 4-9 shows the overall water balance for the plant. Raw water is obtained from groundwater (50 percent) and from municipal sources (50 percent). The water usage represents only the contribution of raw water makeup. In some cases the water demand is greater than raw water makeup because of internal water recycle streams. For example, the boiler feedwater blowdown stream is re-used as makeup to the cooling tower, thus reducing the raw water requirement by that amount.

Exhibit 4-9 Case 9 Water Balance

Water Use	Water Demand, m^3/min (gpm)	Internal Recycle, m^3/min (gpm)	Raw Water Makeup, m^3/min (gpm)
FGD Makeup	2.4 (625)	0	2.4 (625)
BFW Makeup	0.3 (74)	0	0.3 (74)
Cooling Tower Makeup	21.2 (5,587)	0.3 (74)	20.9 (5,513)
Total	**23.9 (6,286)**	**0.3 (74)**	**23.6 (6,212)**

Heat and Mass Balance Diagrams

A heat and mass balance diagram is shown for the Case 9 PC boiler, the FGD unit and steam cycle in Exhibit 4-10.

An overall plant energy balance is provided in tabular form in Exhibit 4-11. The power out is the steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 4-7) is calculated by multiplying the power out by a generator efficiency of 98.6 percent.

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Exhibit 4-10 Case 9 Heat and Mass Balance, Subcritical PC Boiler without CO_2 Capture

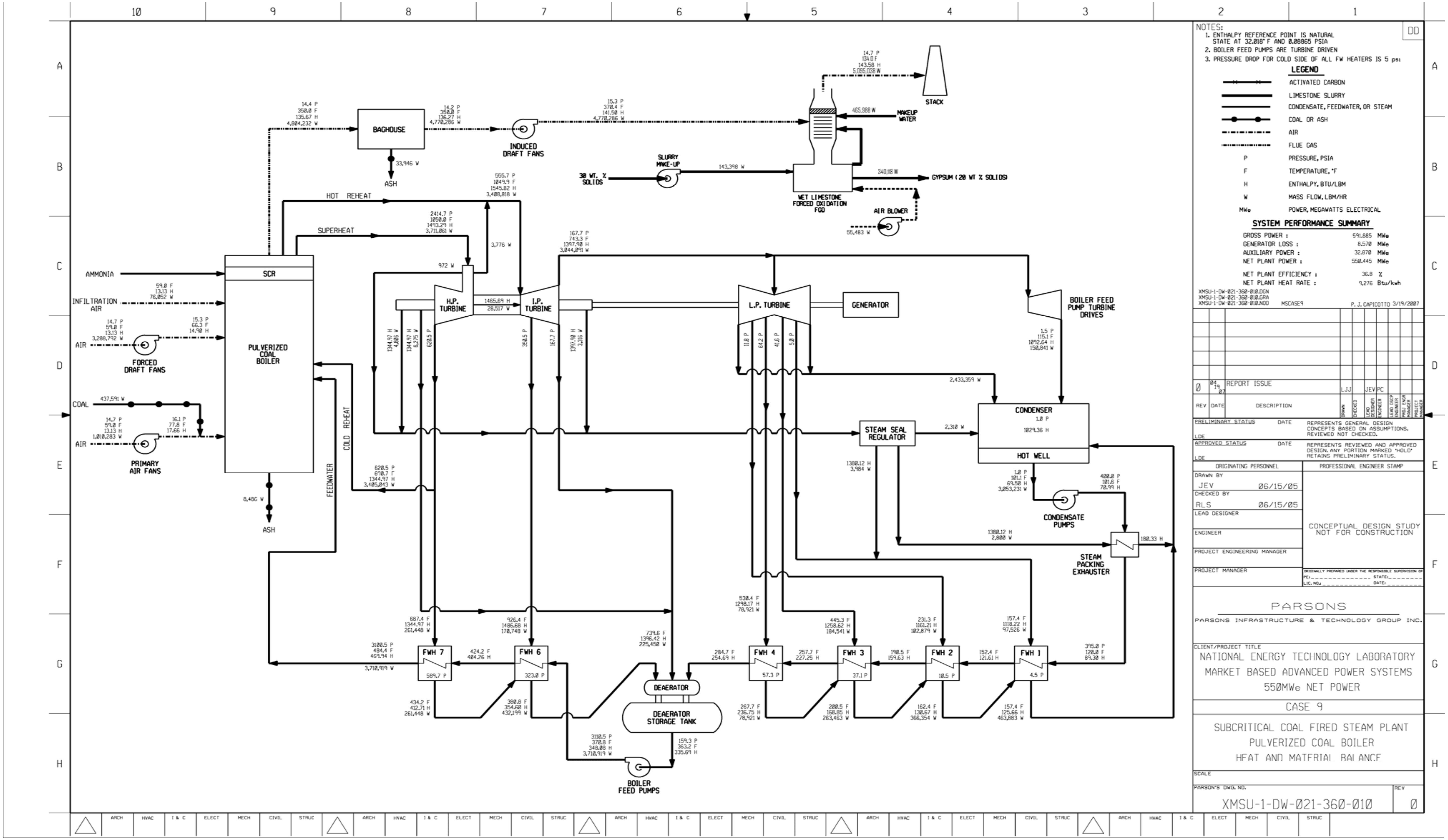

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Exhibit 4-11 Case 9 Overall Energy Balance (0°C [32°F] Reference)

	HHV	Sensible + Latent	Power	Total
Heat In (MMBtu/hr)				
Coal	5,106.2	4.3		5,110.5
Ambient Air		56.5		56.5
Infiltration Air		1.0		1.0
Limestone		64.8		64.8
FGD Oxidant		0.7		0.7
Water		19.0		19.0
Auxiliary Power			112.2	112.2
Totals	**5,106.2**	**146.4**	**112.2**	**5,364.7**
Heat Out (MMBtu/hr)				
Bottom Ash		0.4		0.4
Fly Ash		1.7		1.7
Flue Gas Exhaust		712.5		712.5
Gypsum Slurry		29.9		29.9
Condenser		2,520.0		2,520.0
Process Losses (1)		80.5		80.5
Power			2,019.6	2,019.6
Totals	**0.0**	**3,345.1**	**2,019.6**	**5,364.7**

(1) Process Losses are calculated by difference and reflect various boiler, turbine, and other heat and work losses. Aspen flowsheet balance is within 0.5 percent.

4.2.5 CASE 9 – MAJOR EQUIPMENT LIST

Major equipment items for the subcritical PC plant with no CO_2 capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 4.2.6. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

ACCOUNT 1 COAL AND SORBENT HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	181 tonne (200 ton)	2	0
2	Feeder	Belt	572 tonne/h (630 tph)	2	0
3	Conveyor No. 1	Belt	1,134 tonne/h (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,134 tonne/h (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,134 tonne/h (1,250 tph)	1	0
8	Reclaim Hopper	N/A	45 tonne (50 ton)	2	1
9	Feeder	Vibratory	163 tonne/h (180 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	327 tonne/h (360 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	163 tonne (180 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3" x 0 - 1-1/4" x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	327 tonne/h (360 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	327 tonne/h (360 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	726 tonne (800 ton)	3	0
19	Limestone Truck Unloading Hopper	N/A	36 tonne (40 ton)	1	0
20	Limestone Feeder	Belt	82 tonne/h (90 tph)	1	0
21	Limestone Conveyor No. L1	Belt	82 tonne/h (90 tph)	1	0
22	Limestone Reclaim Hopper	N/A	18 tonne (20 ton)	1	0
23	Limestone Reclaim Feeder	Belt	64 tonne/h (70 tph)	1	0
24	Limestone Conveyor No. L2	Belt	64 tonne/h (70 tph)	1	0
25	Limestone Day Bin	w/ actuator	263 tonne (290 ton)	2	0

ACCOUNT 2 COAL AND SORBENT PREPARATION AND FEED

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	36 tonne/h (40 tph)	6	0
2	Coal Pulverizer	Ball type or equivalent	36 tonne/h (40 tph)	6	0
3	Limestone Weigh Feeder	Gravimetric	22 tonne/h (24 tph)	1	1
4	Limestone Ball Mill	Rotary	22 tonne/h (24 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	83,280 liters (22,000 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	336 lpm @ 12 m H2O (370 gpm @ 40 ft H2O)	1	1
7	Hydroclone Classifier	4 active cyclones in a 5 cyclone bank	82 lpm (90 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1
9	Limestone Slurry Storage Tank with Agitator	Field erected	469,395 liters (124,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	236 lpm @ 9 m H2O (260 gpm @ 30 ft H2O)	1	1

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	1,112,920 liters (294,000 gal)	2	0
2	Condensate Pumps	Vertical canned	25,741 lpm @ 335 m H2O (6,800 gpm @ 1,100 ft H2O)	1	1
3	Deaerator and Storage Tank	Horizontal spray type	1,852,020 kg/h (4,083,000 lb/h) 5 min. tank	1	0
4	Boiler Feed Pump and Steam Turbine Drive	Barrel type, multi-stage, centrifugal	31,041 lpm @ 2,499 m H2O (8,200 gpm @ 8,200 ft H2O)	1	1
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	9,085 lpm @ 2,499 m H2O (2,400 gpm @ 8,200 ft H2O)	1	0
6	LP Feedwater Heater 1A/1B	Horizontal U-tube	762,036 kg/h (1,680,000 lb/h)	2	0
7	LP Feedwater Heater 2A/2B	Horizontal U-tube	762,036 kg/h (1,680,000 lb/h)	2	0
8	LP Feedwater Heater 3A/3B	Horizontal U-tube	762,036 kg/h (1,680,000 lb/h)	2	0
9	LP Feedwater Heater 4A/4B	Horizontal U-tube	762,036 kg/h (1,680,000 lb/h)	2	0
10	HP Feedwater Heater 6	Horizontal U-tube	1,850,659 kg/h (4,080,000 lb/h)	1	0
11	HP Feedwater Heater 7	Horizontal U-tube	1,850,659 kg/h (4,080,000 lb/h)	1	0
12	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/h, 2.8 MPa, 343°C (40,000 lb/h, 400 psig, 650°F)	1	0
13	Fuel Oil System	No. 2 fuel oil for light off	1,135,632 liter (300,000 gal)	1	0
14	Service Air Compressors	Flooded Screw	28 m3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
15	Instrument Air Dryers	Duplex, regenerative	28 m3/min (1,000 scfm)	2	1
16	Closed Cycle Cooling Heat Exchangers	Shell and tube	53 MMkJ/h (50 MMBtu/h) each	2	0
17	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,820 lpm @ 30 m H2O (5,500 gpm @ 100 ft H2O)	2	1
18	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H2O (1,000 gpm @ 290 ft H2O)	1	1
19	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H2O (700 gpm @ 210 ft H2O)	1	1
20	Raw Water Pumps	Stainless steel, single suction	13,098 lpm @ 43 m H2O (3,460 gpm @ 140 ft H2O)	2	1
21	Filtered Water Pumps	Stainless steel, single suction	1,590 lpm @ 49 m H2O (420 gpm @ 160 ft H2O)	2	1
22	Filtered Water Tank	Vertical, cylindrical	1,540,675 liter (407,000 gal)	1	0
23	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	606 lpm (160 gpm)	1	1
24	Liquid Waste Treatment System	--	10 years, 24-hour storm	1	0

ACCOUNT 4 BOILER AND ACCESSORIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Subcritical, drum wall-fired, low NOx burners, overfire air	1,850,659 kg/h steam @ 16.5 MPa/566°C/566°C (4,080,000 lb/h steam @ 2,400 psig/1,050°F/1,050°F)	1	0
2	Primary Air Fan	Centrifugal	252,198 kg/h, 3,455 m3/min @ 123 cm WG (556,000 lb/h, 122,000 acfm @ 48 in. WG)	2	0
3	Forced Draft Fan	Centrifugal	821,457 kg/h, 11,248 m3/min @ 47 cm WG (1,811,000 lb/h, 397,200 acfm @ 19 in. WG)	2	0
4	Induced Draft Fan	Centrifugal	1,191,589 kg/h, 25,301 m3/min @ 90 cm WG (2,627,000 lb/h, 893,500 acfm @ 36 in. WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	2,381,363 kg/h (5,250,000 lb/h)	2	0
6	SCR Catalyst	--	--	3	0
7	Dilution Air Blower	Centrifugal	142 m3/min @ 108 cm WG (5,000 scfm @ 42 in. WG)	2	1
8	Ammonia Storage	Horizontal tank	155,203 liter (41,000 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	30 lpm @ 91 m H2O (8 gpm @ 300 ft H2O)	2	1

ACCOUNT 5 FLUE GAS CLEANUP

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Fabric Filter	Single stage, high-ratio with pulse-jet online cleaning system	1,191,589 kg/h (2,627,000 lb/h) 99.8% efficiency	2	0
2	Absorber Module	Counter-current open spray	40,295 m3/min (1,423,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	140,061 lpm @ 64 m H2O (37,000 gpm @ 210 ft H2O)	5	1
4	Bleed Pumps	Horizontal centrifugal	4,278 lpm (1,130 gpm) at 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	187 m3/min @ 0.3 MPa (6,620 acfm @ 37 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	1,060 lpm (280 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	34 tonne/h (37 tph) of 50 wt % slurry	2	1
9	Filtrate Water Return Pumps	Horizontal centrifugal	644 lpm @ 12 m H2O (170 gpm @ 40 ft H2O)	1	1
10	Filtrate Water Return Storage Tank	Vertical, lined	416,399 lpm (110,000 gal)	1	0
11	Process Makeup Water Pumps	Horizontal centrifugal	2,612 lpm @ 21 m H2O (690 gpm @ 70 ft H2O)	1	1

ACCOUNT 6 COMBUSTION TURBINE/ACCESSORIES

N/A

ACCOUNT 7 HRSG, DUCTING & STACK

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	152 m (500 ft) high x 5.8 m (19 ft) diameter	1	0

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	610 MW 16.5 MPa/566°C/566°C (2400 psig/ 1050°F/1050°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	680 MVA @ 0.9 p.f., 24 kV, 60 Hz	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	2,920 MMkJ/h (2,770 MMBtu/h), Inlet water temperature 16ºC (60ºF), Water temperature rise 11ºC (20ºF)	1	0

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	545,104 lpm @ 30.5 m (144,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT 3,036 MMkJ/h (2,880 MMBtu/h) heat load	1	0

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Economizer Hopper (part of boiler scope of supply)	--	--	4	0
2	Bottom Ash Hopper (part of boiler scope of supply)	--	--	2	0
3	Clinker Grinder	--	4.5 tonne/h (5 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	--	--	6	0
5	Hydroejectors	--	--	12	
6	Economizer /Pyrites Transfer Tank	--	--	1	0
7	Ash Sluice Pumps	Vertical, wet pit	151 lpm @ 17 m H2O (40 gpm @ 56 ft H2O)	1	1
8	Ash Seal Water Pumps	Vertical, wet pit	7,571 lpm @ 9 m H2O (2000 gpm @ 28 ft H2O)	1	1
9	Hydrobins	--	151 lpm (40 gpm)	1	1
10	Baghouse Hopper (part of baghouse scope of supply)	--	--	24	0
11	Air Heater Hopper (part of boiler scope of supply)	--	--	10	0
12	Air Blower	--	16 m3/min @ 0.2 MPa (550 scfm @ 24 psi)	1	1
13	Fly Ash Silo	Reinforced concrete	499 tonne (1,100 ton)	2	0
14	Slide Gate Valves	--	--	2	0
15	Unloader	--	--	1	0
16	Telescoping Unloading Chute	--	91 tonne/h (100 tph)	1	0

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 650 MVA, 3-ph, 60 Hz	1	0
2	Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 35 MVA, 3-ph, 60 Hz	1	1
3	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 5 MVA, 3-ph, 60 Hz	1	1
4	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
5	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
6	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
7	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

ACCOUNT 12 INSTRUMENTATION AND CONTROL

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

4.2.6 CASE 9 – COST ESTIMATING

The cost estimating methodology was described previously in Section 2.6. Exhibit 4-12 shows the total plant capital cost summary organized by cost account and Exhibit 4-13 shows a more detailed breakdown of the capital costs. Exhibit 4-14 shows the initial and annual O&M costs.

The estimated TPC of the subcritical PC boiler with no CO_2 capture is $1,548/kW. No process contingency is included in this case because all elements of the technology are commercially proven. The project contingency is 11.2 percent of the TPC. The 20-year LCOE is 64.0 mills/kWh

Exhibit 4-12 Case 9 Total Plant Cost Summary

Client: USDOE/NETL **Report Date:** 09-May-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 9 - Subcritical PC w/o CO2
Plant Size: 550.4 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	$16,102	$4,348	$9,748	$0	$0	**$30,198**	$2,706	$0	$4,936	**$37,840**	$69
2	COAL & SORBENT PREP & FEED	$10,847	$629	$2,750	$0	$0	**$14,227**	$1,247	$0	$2,321	**$17,795**	$32
3	FEEDWATER & MISC. BOP SYSTEMS	$37,503	$0	$18,011	$0	$0	**$55,514**	$5,071	$0	$9,963	**$70,548**	$128
4	PC BOILER											
4.1	PC Boiler & Accessories	$127,763	$0	$82,570	$0	$0	**$210,334**	$20,391	$0	$23,072	**$253,797**	$461
4.2	SCR (w/4.1)	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.3	Open	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.4-4.9	Boiler BoP (w/ ID Fans)	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
	SUBTOTAL 4	**$127,763**	**$0**	**$82,570**	**$0**	**$0**	**$210,334**	**$20,391**	**$0**	**$23,072**	**$253,797**	**$461**
5	FLUE GAS CLEANUP	$83,756	$0	$28,598	$0	$0	**$112,354**	$10,675	$0	$12,303	**$135,332**	$246
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	N/A	$0	N/A	$0	$0	**$0**	$0	$0	$0	**$0**	$0
6.2-6.9	Combustion Turbine Other	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
	SUBTOTAL 6	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	N/A	$0	N/A	$0	$0	**$0**	$0	$0	$0	**$0**	$0
7.2-7.9	HRSG Accessories, Ductwork and Stack	$17,476	$1,006	$11,965	$0	$0	**$30,447**	$2,787	$0	$4,336	**$37,570**	$68
	SUBTOTAL 7	**$17,476**	**$1,006**	**$11,965**	**$0**	**$0**	**$30,447**	**$2,787**	**$0**	**$4,336**	**$37,570**	**$68**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$47,000	$0	$6,220	$0	$0	**$53,220**	$5,095	$0	$5,832	**$64,147**	$117
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$22,612	$1,045	$12,107	$0	$0	**$35,764**	$3,134	$0	$5,418	**$44,316**	$81
	SUBTOTAL 8	**$69,612**	**$1,045**	**$18,328**	**$0**	**$0**	**$88,984**	**$8,230**	**$0**	**$11,249**	**$108,463**	**$197**
9	COOLING WATER SYSTEM	$11,659	$6,571	$11,683	$0	$0	**$29,913**	$2,792	$0	$4,499	**$37,204**	$68
10	ASH/SPENT SORBENT HANDLING SYS	$4,383	$138	$5,829	$0	$0	**$10,350**	$985	$0	$1,166	**$12,502**	$23
11	ACCESSORY ELECTRIC PLANT	$15,802	$6,032	$17,773	$0	$0	**$39,607**	$3,506	$0	$5,366	**$48,479**	$88
12	INSTRUMENTATION & CONTROL	$8,006	$0	$8,413	$0	$0	**$16,419**	$1,503	$0	$2,204	**$20,126**	$37
13	IMPROVEMENTS TO SITE	$2,833	$1,629	$5,752	$0	$0	**$10,214**	$1,003	$0	$2,243	**$13,460**	$24
14	BUILDINGS & STRUCTURES	$0	$22,304	$21,358	$0	$0	**$43,662**	$3,934	$0	$11,899	**$59,495**	$108
	TOTAL COST	**$405,742**	**$43,703**	**$242,779**	**$0**	**$0**	**$692,224**	**$64,830**	**$0**	**$95,558**	**$852,612**	**$1,549**

Exhibit 4-13 Case 9 Total Plant Cost Details

	Client:	USDOE/NETL								Report Date:	09-May-07		
	Project:	Bituminous Baseline Study											
		TOTAL PLANT COST SUMMARY											
	Case:	Case 9 - Subcritical PC w/o CO2											
	Plant Size:	550.4 MW,net		Estimate Type:		Conceptual				Cost Base (Dec)	2006	($x1000)	

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	$3,308	$0	$1,527	$0	$0	$4,834	$432	$0	$790	$6,056	$11
1.2	Coal Stackout & Reclaim	$4,275	$0	$979	$0	$0	$5,254	$460	$0	$857	$6,571	$12
1.3	Coal Conveyors	$3,975	$0	$968	$0	$0	$4,943	$433	$0	$806	$6,183	$11
1.4	Other Coal Handling	$1,040	$0	$224	$0	$0	$1,264	$110	$0	$206	$1,581	$3
1.5	Sorbent Receive & Unload	$133	$0	$40	$0	$0	$173	$15	$0	$28	$217	$0
1.6	Sorbent Stackout & Reclaim	$2,145	$0	$397	$0	$0	$2,542	$221	$0	$414	$3,177	$6
1.7	Sorbent Conveyors	$765	$165	$190	$0	$0	$1,119	$97	$0	$182	$1,399	$3
1.8	Other Sorbent Handling	$462	$108	$245	$0	$0	$815	$72	$0	$133	$1,020	$2
1.9	Coal & Sorbent Hnd.Foundations	$0	$4,076	$5,178	$0	$0	$9,254	$865	$0	$1,518	$11,637	$21
	SUBTOTAL 1.	**$16,102**	**$4,348**	**$9,748**	**$0**	**$0**	**$30,198**	**$2,706**	**$0**	**$4,936**	**$37,840**	**$69**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	$1,900	$0	$374	$0	$0	$2,274	$198	$0	$371	$2,843	$5
2.2	Coal Conveyor to Storage	$4,864	$0	$1,073	$0	$0	$5,936	$519	$0	$968	$7,424	$13
2.3	Coal Injection System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.4	Misc.Coal Prep & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.5	Sorbent Prep Equipment	$3,645	$156	$765	$0	$0	$4,566	$398	$0	$745	$5,708	$10
2.6	Sorbent Storage & Feed	$439	$0	$170	$0	$0	$609	$54	$0	$99	$763	$1
2.7	Sorbent Injection System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.8	Booster Air Supply System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.9	Coal & Sorbent Feed Foundation	$0	$473	$369	$0	$0	$842	$78	$0	$138	$1,057	$2
	SUBTOTAL 2.	**$10,847**	**$629**	**$2,750**	**$0**	**$0**	**$14,227**	**$1,247**	**$0**	**$2,321**	**$17,795**	**$32**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	$15,086	$0	$5,277	$0	$0	$20,363	$1,787	$0	$3,322	$25,472	$46
3.2	Water Makeup & Pretreating	$4,700	$0	$1,511	$0	$0	$6,211	$582	$0	$1,359	$8,152	$15
3.3	Other Feedwater Subsystems	$4,982	$0	$2,114	$0	$0	$7,095	$632	$0	$1,159	$8,887	$16
3.4	Service Water Systems	$928	$0	$501	$0	$0	$1,429	$133	$0	$312	$1,873	$3
3.5	Other Boiler Plant Systems	$5,826	$0	$5,699	$0	$0	$11,525	$1,081	$0	$1,891	$14,498	$26
3.6	FO Supply Sys & Nat Gas	$248	$0	$305	$0	$0	$552	$51	$0	$91	$694	$1
3.7	Waste Treatment Equipment	$3,168	$0	$1,815	$0	$0	$4,982	$483	$0	$1,093	$6,558	$12
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	$2,566	$0	$790	$0	$0	$3,356	$322	$0	$736	$4,414	$8
	SUBTOTAL 3.	**$37,503**	**$0**	**$18,011**	**$0**	**$0**	**$55,514**	**$5,071**	**$0**	**$9,963**	**$70,548**	**$128**
4	PC BOILER											
4.1	PC Boiler & Accessories	$127,763	$0	$82,570	$0	$0	$210,334	$20,391	$0	$23,072	$253,797	$461
4.2	SCR (w/4.1)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.3	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.4	Boiler BoP (w/ ID Fans)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.5	Primary Air System	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.6	Secondary Air System	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.8	Major Component Rigging	$0	w/4.1	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.9	Boiler Foundations	$0	w/14.1	w/14.1	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 4.	**$127,763**	**$0**	**$82,570**	**$0**	**$0**	**$210,334**	**$20,391**	**$0**	**$23,072**	**$253,797**	**$461**

Exhibit 4-13 Case 9 Total Plant Cost Details (Continued)

Client: USDOE/NETL **Report Date:** 09-May-07

Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 9 - Subcritical PC w/o CO2

Plant Size: 550.4 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5	FLUE GAS CLEANUP											
5.1	Absorber Vessels & Accessories	$58,310	$0	$12,562	$0	$0	$70,872	$6,708	$0	$7,758	$85,337	$155
5.2	Other FGD	$3,043	$0	$3,451	$0	$0	$6,494	$626	$0	$712	$7,831	$14
5.3	Bag House & Accessories	$16,683	$0	$10,596	$0	$0	$27,279	$2,609	$0	$2,989	$32,877	$60
5.4	Other Particulate Removal Materials	$1,129	$0	$1,209	$0	$0	$2,338	$225	$0	$256	$2,819	$5
5.5	Gypsum Dewatering System	$4,591	$0	$780	$0	$0	$5,372	$508	$0	$588	$6,467	$12
5.6	Mercury Removal System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5.9	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 5.	**$83,756**	**$0**	**$28,598**	**$0**	**$0**	**$112,354**	**$10,675**	**$0**	**$12,303**	**$135,332**	**$246**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
6.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.3	Compressed Air Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.9	Combustion Turbine Foundations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 6.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
7.2	HRSG Accessories	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$8,649	$0	$5,645	$0	$0	$14,295	$1,249	$0	$2,332	$17,875	$32
7.4	Stack	$8,826	$0	$5,169	$0	$0	$13,995	$1,337	$0	$1,533	$16,866	$31
7.9	Duct & Stack Foundations	$0	$1,006	$1,151	$0	$0	$2,157	$201	$0	$472	$2,830	$5
	SUBTOTAL 7.	**$17,476**	**$1,006**	**$11,965**	**$0**	**$0**	**$30,447**	**$2,787**	**$0**	**$4,336**	**$37,570**	**$68**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$47,000	$0	$6,220	$0	$0	$53,220	$5,095	$0	$5,832	$64,147	$117
8.2	Turbine Plant Auxiliaries	$335	$0	$718	$0	$0	$1,054	$102	$0	$116	$1,271	$2
8.3	Condenser & Auxiliaries	$7,062	$0	$2,211	$0	$0	$9,272	$880	$0	$1,015	$11,168	$20
8.4	Steam Piping	$15,215	$0	$7,516	$0	$0	$22,731	$1,897	$0	$3,694	$28,322	$51
8.9	TG Foundations	$0	$1,045	$1,663	$0	$0	$2,708	$255	$0	$592	$3,555	$6
	SUBTOTAL 8.	**$69,612**	**$1,045**	**$18,328**	**$0**	**$0**	**$88,984**	**$8,230**	**$0**	**$11,249**	**$108,463**	**$197**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$8,335	$0	$2,730	$0	$0	$11,065	$1,051	$0	$1,212	$13,328	$24
9.2	Circulating Water Pumps	$1,938	$0	$127	$0	$0	$2,065	$177	$0	$224	$2,466	$4
9.3	Circ.Water System Auxiliaries	$516	$0	$69	$0	$0	$585	$55	$0	$64	$704	$1
9.4	Circ.Water Piping	$0	$4,162	$3,969	$0	$0	$8,131	$749	$0	$1,332	$10,212	$19
9.5	Make-up Water System	$458	$0	$607	$0	$0	$1,065	$101	$0	$175	$1,341	$2
9.6	Component Cooling Water Sys	$412	$0	$326	$0	$0	$738	$69	$0	$121	$928	$2
9.9	Circ.Water System Foundations& Structures	$0	$2,409	$3,855	$0	$0	$6,265	$590	$0	$1,371	$8,225	$15
	SUBTOTAL 9.	**$11,659**	**$6,571**	**$11,683**	**$0**	**$0**	**$29,913**	**$2,792**	**$0**	**$4,499**	**$37,204**	**$68**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Ash Coolers	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.2	Cyclone Ash Letdown	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.3	HGCU Ash Letdown	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.4	High Temperature Ash Piping	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.5	Other Ash Recovery Equipment	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$583	$0	$1,798	$0	$0	$2,381	$232	$0	$261	$2,874	$5
10.7	Ash Transport & Feed Equipment	$3,800	$0	$3,869	$0	$0	$7,669	$725	$0	$839	$9,234	$17
10.8	Misc. Ash Handling Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.9	Ash/Spent Sorbent Foundation	$0	$138	$163	$0	$0	$301	$28	$0	$66	$395	$1
	SUBTOTAL 10.	**$4,383**	**$138**	**$5,829**	**$0**	**$0**	**$10,350**	**$985**	**$0**	**$1,166**	**$12,502**	**$23**

Exhibit 4-13 Case 9 Total Plant Cost Details (Continued)

Client: USDOE/NETL **Report Date:** 09-May-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 9 - Subcritical PC w/o CO2
Plant Size: 550.4 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$1,527	$0	$250	$0	$0	$1,777	$165	$0	$146	$2,088	$4
11.2	Station Service Equipment	$2,671	$0	$914	$0	$0	$3,585	$343	$0	$295	$4,222	$8
11.3	Switchgear & Motor Control	$3,174	$0	$544	$0	$0	$3,717	$344	$0	$406	$4,468	$8
11.4	Conduit & Cable Tray	$0	$2,038	$6,935	$0	$0	$8,973	$859	$0	$1,475	$11,306	$21
11.5	Wire & Cable	$0	$3,696	$7,305	$0	$0	$11,002	$927	$0	$1,789	$13,718	$25
11.6	Protective Equipment	$252	$0	$894	$0	$0	$1,146	$112	$0	$126	$1,384	$3
11.7	Standby Equipment	$1,178	$0	$28	$0	$0	$1,206	$114	$0	$132	$1,452	$3
11.8	Main Power Transformers	$7,000	$0	$166	$0	$0	$7,166	$544	$0	$771	$8,481	$15
11.9	Electrical Foundations	$0	$298	$737	$0	$0	$1,035	$98	$0	$227	$1,360	$2
	SUBTOTAL 11.	**$15,802**	**$6,032**	**$17,773**	**$0**	**$0**	**$39,607**	**$3,506**	**$0**	**$5,366**	**$48,479**	**$88**
12	INSTRUMENTATION & CONTROL											
12.1	PC Control Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
12.3	Steam Turbine Control	w/8.1	$0	w/8.1	$0	$0	$0	$0	$0	$0	$0	$0
12.4	Other Major Component Control	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
12.5	Signal Processing Equipment	W/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.6	Control Boards,Panels & Racks	$410	$0	$256	$0	$0	$666	$64	$0	$109	$839	$2
12.7	Distributed Control System Equipment	$4,139	$0	$754	$0	$0	$4,893	$466	$0	$536	$5,895	$11
12.8	Instrument Wiring & Tubing	$2,287	$0	$4,638	$0	$0	$6,924	$590	$0	$1,127	$8,641	$16
12.9	Other I & C Equipment	$1,170	$0	$2,766	$0	$0	$3,935	$383	$0	$432	$4,750	$9
	SUBTOTAL 12.	**$8,006**	**$0**	**$8,413**	**$0**	**$0**	**$16,419**	**$1,503**	**$0**	**$2,204**	**$20,126**	**$37**
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation	$0	$48	$959	$0	$0	$1,007	$99	$0	$221	$1,328	$2
13.2	Site Improvements	$0	$1,581	$1,978	$0	$0	$3,559	$349	$0	$782	$4,690	$9
13.3	Site Facilities	$2,833	$0	$2,815	$0	$0	$5,648	$554	$0	$1,240	$7,442	$14
	SUBTOTAL 13.	**$2,833**	**$1,629**	**$5,752**	**$0**	**$0**	**$10,214**	**$1,003**	**$0**	**$2,243**	**$13,460**	**$24**
14	BUILDINGS & STRUCTURES											
14.1	Boiler Building	$0	$8,070	$7,192	$0	$0	$15,261	$1,371	$0	$4,158	$20,790	$38
14.2	Turbine Building	$0	$11,680	$11,031	$0	$0	$22,711	$2,045	$0	$6,189	$30,945	$56
14.3	Administration Building	$0	$555	$594	$0	$0	$1,149	$104	$0	$313	$1,566	$3
14.4	Circulation Water Pumphouse	$0	$159	$128	$0	$0	$287	$26	$0	$78	$391	$1
14.5	Water Treatment Buildings	$0	$620	$518	$0	$0	$1,138	$102	$0	$310	$1,550	$3
14.6	Machine Shop	$0	$371	$253	$0	$0	$624	$55	$0	$170	$849	$2
14.7	Warehouse	$0	$251	$256	$0	$0	$507	$46	$0	$138	$691	$1
14.8	Other Buildings & Structures	$0	$205	$177	$0	$0	$383	$34	$0	$104	$521	$1
14.9	Waste Treating Building & Str.	$0	$393	$1,209	$0	$0	$1,603	$151	$0	$439	$2,193	$4
	SUBTOTAL 14.	**$0**	**$22,304**	**$21,358**	**$0**	**$0**	**$43,662**	**$3,934**	**$0**	**$11,899**	**$59,495**	**$108**
	TOTAL COST	**$405,742**	**$43,703**	**$242,779**	**$0**	**$0**	**$692,224**	**$64,830**	**$0**	**$95,558**	**$852,612**	**$1,549**

Exhibit 4-14 Case 9 Initial and Annual Operating and Maintenance Costs

INITIAL & ANNUAL O&M EXPENSES							
Case 9 - Subcritical PC w/o CO2					Cost Base (Dec)	2006	
					Heat Rate-net(Btu/kWh):	9,276	
					MWe-net:	550	
					Capacity Factor: (%):	85	
OPERATING & MAINTENANCE LABOR							
Operating Labor							
Operating Labor Rate(base):	33.00	$/hour					
Operating Labor Burden:	30.00	% of base					
Labor O-H Charge Rate:	25.00	% of labor					
			Total				
Skilled Operator	2.0		2.0				
Operator	9.0		9.0				
Foreman	1.0		1.0				
Lab Tech's, etc.	2.0		2.0				
TOTAL-O.J.'s	14.0		14.0				
					Annual Cost $	Annual Unit Cost $/kW-net	
Annual Operating Labor Cost					$5,261,256	$9.558	
Maintenance Labor Cost					$5,602,943	$10.179	
Administrative & Support Labor					$2,716,050	$4.934	
TOTAL FIXED OPERATING COSTS					**$13,580,249**	**$24.672**	
VARIABLE OPERATING COSTS							
						$/kWh-net	
Maintenance Material Cost					**$8,404,415**	**$0.00205**	
Consumables	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost			
Water(/1000 gallons)	0	4,472.64	1.03	**$0**	**$1,429,266**	**$0.00035**	
Chemicals							
MU & WT Chem.(lb)	151,553	21,650	0.16	$24,976	$1,106,970	$0.00027	
Limestone (ton)	3,661	523	20.60	$75,419	$3,342,699	$0.00082	
Carbon (Mercury Removal) (lb)	0	0	0.00	$0	$0	$0.00000	
MEA Solvent (ton)	0	0	2,142.40	$0	$0	$0.00000	
NaOH (tons)	0	0	412.96	$0	$0	$0.00000	
H2SO4 (tons)	0	0	132.15	$0	$0	$0.00000	
Corrosion Inhibitor	0	0	0.00	$0	$0	$0.00000	
Activated Carbon(lb)	0	0	1.00	$0	$0	$0.00000	
Ammonia (28% NH3) ton	550	79	123.60	$67,984	$3,013,146	$0.00074	
Subtotal Chemicals				**$168,379**	**$7,462,815**	**$0.00182**	
Other							
Supplemental Fuel(MBtu)	0	0	0.00	$0	$0	$0.00000	
SCR Catalyst(m3)	w/equip.	0.47	5,500.00	$0	$794,147	$0.00019	
Emission Penalties	0	0	0.00	$0	$0	$0.00000	
Subtotal Other				**$0**	**$794,147**	**$0.00019**	
Waste Disposal							
Flyash (ton)	0	102	15.45	$0	$488,290	$0.00012	
Bottom Ash(ton)	0	407	15.45	$0	$1,953,046	$0.00048	
Subtotal-Waste Disposal				**$0**	**$2,441,336**	**$0.00060**	
By-products & Emissions							
Gypsum (tons)	0	823	0.00	$0	$0	$0.00000	
Subtotal By-Products				**$0**	**$0**	**$0.00000**	
TOTAL VARIABLE OPERATING COSTS				**$168,379**	**$20,531,979**	**$0.00501**	
Fuel(ton)	157,562	5,252	42.11	**$6,634,942**	**$68,616,356**	**$0.01674**	

4.2.7 CASE 10 – PC SUBCRITICAL UNIT WITH CO_2 CAPTURE

The plant configuration for Case 10, subcritical PC, is the same as Case 9 with the exception that the Econamine FG Plus technology was added for CO_2 capture. The nominal net output was maintained at 550 MW by increasing the boiler size and turbine/generator size to account for the greater auxiliary load imposed by the CDR facility. Unlike the IGCC cases where gross output was fixed by the available size of the combustion turbines, the PC cases utilize boilers and steam turbines that can be procured at nearly any desired output making it possible to maintain a constant net output.

The process description for Case 10 is essentially the same as Case 9 with one notable exception, the addition of CO_2 capture. A BFD and stream tables for Case 10 are shown in Exhibit 4-15 and Exhibit 4-16, respectively. Since the CDR facility process description was provided in Section 4.1.7, it is not repeated here.

4.2.8 CASE 10 PERFORMANCE RESULTS

The Case 10 modeling assumptions were presented previously in Section 4.2.2.

The plant produces a net output of 550 MW at a net plant efficiency of 24.9 percent (HHV basis). Overall plant performance is summarized in Exhibit 4-17 which includes auxiliary power requirements. The CDR facility, including CO_2 compression, accounts for over half of the auxiliary plant load. The circulating water system (circulating water pumps and cooling tower fan) accounts for over 15 percent of the auxiliary load, largely due to the high cooling water demand of the CDR facility.

Exhibit 4-15 Case 10 Process Flow Diagram, Subcritical Unit with CO_2 Capture

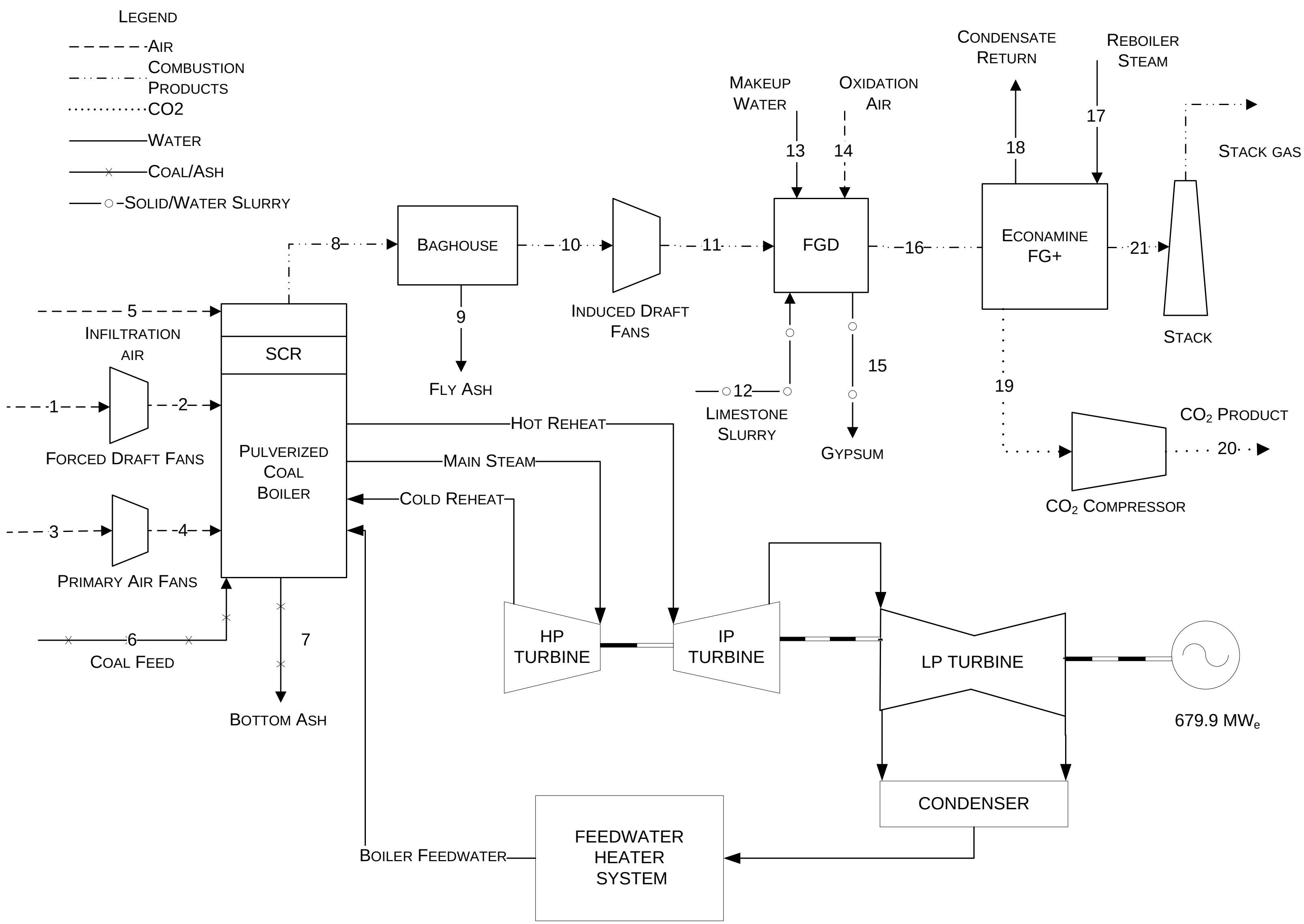

Exhibit 4-16 Case 10 Stream Table, Subcritical Unit with CO_2 Capture

	1	2	3	4	5	6	7	8	9	10	11
V-L Mole Fraction											
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0087	0.0000	0.0087	0.0087
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.1448	0.0000	0.1448	0.1448
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	0.0869	0.0000	0.0869	0.0869
N_2	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.7325	0.0000	0.7325	0.7325
O_2	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0250	0.0000	0.0250	0.0250
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021	0.0000	0.0021	0.0021
Total	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	0.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	168,844	168,844	51,867	51,867	3,894	0	0	237,558	0	237,558	237,558
V-L Flowrate (lb/hr)	4,872,330	4,872,330	1,496,730	1,496,730	112,375	0	0	7,065,320	0	7,065,320	7,065,320
Solids Flowrate (lb/hr)	0	0	0	0	0	646,589	12,540	50,159	50,159	0	0
Temperature (°F)	59	66	59	78	59	78	350	350	350	350	370
Pressure (psia)	14.7	15.3	14.7	16.1	14.7	14.7	14.4	14.4	14.2	14.2	15.3
Enthalpy (BTU/lb)[A]	13.1	14.9	13.1	17.7	13.1	11,676	51.4	135.7	51.4	136.3	141.5
Density (lb/ft^3)	0.08	0.08	0.08	0.08	0.08	--	--	0.05	--	0.05	0.05
Molecular Weight	28.86	28.86	28.86	28.86	28.86	--	--	29.74	--	29.74	29.74

	12	13	14	15	16	17	18	19	20	21
V-L Mole Fraction										
Ar	0.0000	0.0000	0.0092	0.0000	0.0079	0.0000	0.0000	0.0000	0.0000	0.0107
CO_2	0.0000	0.0000	0.0003	0.0014	0.1314	0.0000	0.0000	0.9856	1.0000	0.0176
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	1.0000	1.0000	0.0099	0.9978	0.1725	1.0000	1.0000	0.0144	0.0000	0.0458
N_2	0.0000	0.0000	0.7732	0.0007	0.6644	0.0000	0.0000	0.0000	0.0000	0.8940
O_2	0.0000	0.0000	0.2074	0.0000	0.0237	0.0000	0.0000	0.0000	0.0000	0.0319
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	8,120	40,086	2,816	22,176	265,166	110,756	110,756	31,826	31,369	197,020
V-L Flowrate (lb/hr)	146,287	722,155	81,276	400,501	7,578,830	1,995,300	1,995,300	1,388,770	1,380,530	5,535,170
Solids Flowrate (lb/hr)	63,956	0	0	99,659	0	0	0	0	0	0
Temperature (°F)	59	59	59	135	135	743	367	69	124	89
Pressure (psia)	14.7	14.7	14.7	14.7	14.7	167.7	167.7	23.5	2,215.0	14.7
Enthalpy (BTU/lb)[A]	---	32.4	13.1	88.0	143.6	1397.7	340.1	13.7	-70.8	45.7
Density (lb/ft^3)	62.62	62.62	0.08	40.44	0.07	0.24	54.94	0.18	40.76	0.07
Molecular Weight	18.02	18.02	28.86	18.06	28.58	18.02	18.02	43.64	44.01	28.09

A - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 4-17 Case 10 Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
TOTAL (STEAM TURBINE) POWER, kWe	**679,923**
AUXILIARY LOAD SUMMARY, kWe (Note 1)	
Coal Handling and Conveying	520
Limestone Handling & Reagent Preparation	1,400
Pulverizers	4,400
Ash Handling	840
Primary Air Fans	2,060
Forced Draft Fans	2,620
Induced Draft Fans	11,180
SCR	80
Baghouse	100
FGD Pumps and Agitators	4,680
Amine System Auxiliaries	23,500
CO_2 Compression	51,610
Condensate Pumps	1,210
Miscellaneous Balance of Plant (Note 2)	2,000
Steam Turbine Auxiliaries	400
Circulating Water Pumps	14,060
Cooling Tower Fans	7,270
Transformer Loss	2,380
TOTAL AUXILIARIES, kWe	**130,310**
NET POWER, kWe	**549,613**
Net Plant Efficiency (HHV)	24.9%
Net Plant Heat Rate (Btu/kWh)	13,724
CONDENSER COOLING DUTY 10^6 kJ/h (10^6 Btu/h)	2,318 (2,199)
CONSUMABLES	
As-Received Coal Feed, kg/h (lb/h)	293,288 (646,589)
Limestone Sorbent Feed, kg/h (lb/h)	29,010 (63,956)
Thermal Input, kWt	2,210,668
Makeup water, m^3/min (gpm)	53.4 (14,098)

Notes: 1. Boiler feed pumps are steam turbine driven
2. Includes plant control systems, lighting, HVAC and miscellanous low voltage loads

Environmental Performance

The environmental targets for emissions of Hg, NOx, SO_2, and particulate matter were presented in Section 2.4. A summary of the plant air emissions for Case 10 is presented in Exhibit 4-18.

Exhibit 4-18 Case 10 Air Emissions

	kg/GJ ($lb/10^6$ Btu)	Tonne/year (ton/year) 85% capacity factor	kg/MWh (lb/MWh)
SO_2	Negligible	Negligible	Negligible
NO_X	0.030 (0.070)	1,783 (1,966)	0.352 (0.777)
Particulates	0.006 (0.013)	331 (365)	0.065 (0.144)
Hg	0.49×10^{-6} (1.14×10^{-6})	0.029 (0.032)	5.8×10^{-6} (12.7×10^{-6})
CO_2	8.7 (20)	517,000 (570,000)	102 (225)
CO_2[1]			126 (278)

[1] CO_2 emissions based on net power instead of gross power

SO_2 emissions are controlled using a wet limestone forced oxidation scrubber that achieves a removal efficiency of 98 percent. The byproduct calcium sulfate is dewatered and stored on site. The wallboard grade material can potentially be marketed and sold, but since it is highly dependent on local market conditions, no byproduct credit was taken. The SO_2 emissions are further reduced to 10 ppmv using an NaOH based polishing scrubber in the CDR facility. The remaining low concentration of SO_2 is essentially completely removed in the CDR absorber vessel resulting in negligible SO_2 emissions.

NOx emissions are controlled to about 0.5 $lb/10^6$ Btu through the use of LNBs and OFA. An SCR unit then further reduces the NOx concentration by 86 percent to 0.07 $lb/10^6$ Btu.

Particulate emissions are controlled using a pulse jet fabric filter which operates at an efficiency of 99.8 percent.

Co-benefit capture results in a 90 percent reduction of mercury emissions. Ninety percent of the CO_2 in the flue gas is removed in CDR facility.

Exhibit 4-19 shows the overall water balance for the plant. Raw water is obtained from groundwater (50 percent) and from municipal sources (50 percent). The water usage represents only the contribution of raw water makeup. In some cases the actual consumption is greater than raw water makeup because of internal water recycle streams. For example, the boiler feedwater blowdown stream and condensate from cooling the flue gas prior to the CDR facility are re-used as makeup to the cooling tower, thus reducing the raw water requirement by that amount.

Exhibit 4-19 Case 10 Water Balance

Water Use	Water Demand, m^3/min (gpm)	Internal Recycle, m^3/min (gpm)	Raw Water Makeup, m^3/min (gpm)
FGD Makeup	3.5 (926)	0	3.5 (926)
BFW Makeup	0.4 (109)	0	0.4 (109)
Cooling Tower Makeup	47.5 (12,543)	5.3 (1,390)	42.2 (11,152)
Total	**51.4 (13,578)**	**5.3 (1,390)**	**46.1 (12,187)**

Heat and Mass Balance Diagrams

A heat and mass balance diagram is shown for the Case 10 PC boiler, the FGD unit, CDR system and steam cycle in Exhibit 4-20.

An overall plant energy balance is provided in tabular form in Exhibit 4-21. The power out is the steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 4-17) is calculated by multiplying the power out by a generator efficiency of 98.4 percent. The Econamine process heat out stream represents heat rejected to cooling water and ultimately to ambient via the cooling tower. The same is true of the condenser heat out stream. The CO_2 compressor intercooler load is included in the Econamine process heat out stream.

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Exhibit 4-20 Case 10 Heat and Mass Balance, Subcritical PC Boiler with CO_2 Capture

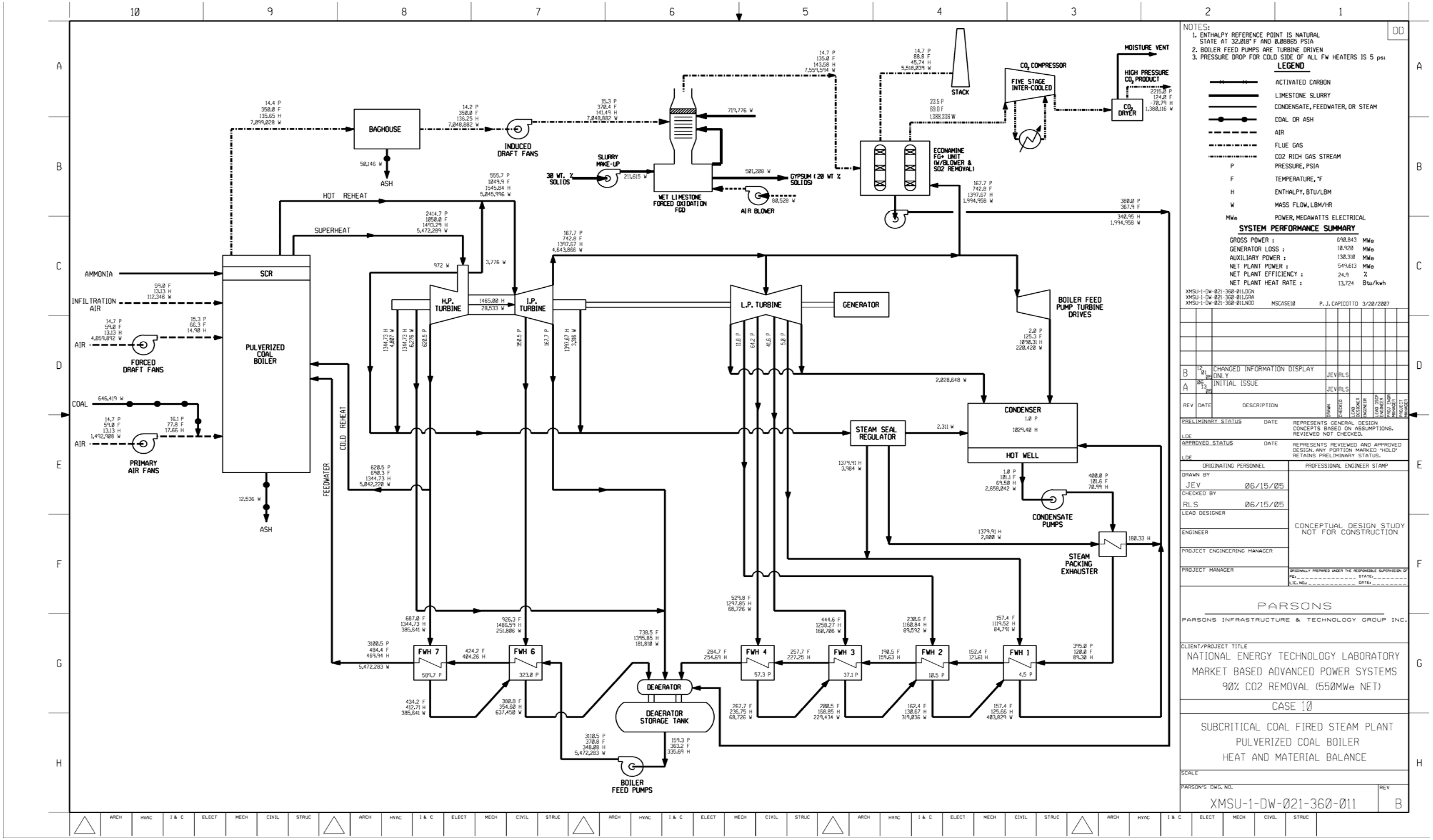

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Exhibit 4-21 Case 10 Overall Energy Balance (0°C [32°F] Reference)

	HHV	Sensible + Latent	Power	Total
Heat In (MMBtu/hr)				
Coal	7,543.1	6.3		7,549.4
Ambient Air		83.6		83.6
Infiltration Air		1.5		1.5
Limestone		96.0		96.0
FGD Oxidant		1.1		1.1
Raw Water Makeup		161.8		161.8
Auxiliary Power			472.3	472.3
Totals	**7,543.1**	**350.2**	**472.3**	**8,365.6**
Heat Out (MMBtu/hr)				
Bottom Ash		0.6		0.6
Fly Ash		2.6		2.6
Flue Gas Exhaust		253.0		253.0
CO_2 Product		(96.8)		(96.8)
Condenser		2,200.0		2,200.0
Econamine Process		3514.7		3514.7
Cooling Tower Blowdown		73.1		73.1
Gypsum Slurry		3.1		3.1
Process Losses (1)		56.0		56.0
Power			2,359.2	2,359.2
Totals	**0.0**	**6,006.4**	**2,359.2**	**8,365.6**

(1) Process Losses are calculated by difference and reflect various boiler, turbine, and other heat and work losses. Aspen flowsheet balance is within 0.5 percent.

4.2.9 CASE 10 – MAJOR EQUIPMENT LIST

Major equipment items for the subcritical PC plant with CO_2 capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 4.2.10. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

ACCOUNT 1 FUEL AND SORBENT HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	181 tonne (200 ton)	2	0
2	Feeder	Belt	572 tonne/h (630 tph)	2	0
3	Conveyor No. 1	Belt	1,134 tonne/h (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,134 tonne/h (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,134 tonne/h (1,250 tph)	1	0
8	Reclaim Hopper	N/A	64 tonne (70 ton)	2	1
9	Feeder	Vibratory	245 tonne/h (270 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	481 tonne/h (530 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	245 tonne (270 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3" x 0 - 1-1/4" x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	481 tonne/h (530 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	481 tonne/h (530 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	1,089 tonne (1,200 ton)	3	0
19	Limestone Truck Unloading Hopper	N/A	36 tonne (40 ton)	1	0
20	Limestone Feeder	Belt	118 tonne/h (130 tph)	1	0
21	Limestone Conveyor No. L1	Belt	118 tonne/h (130 tph)	1	0
22	Limestone Reclaim Hopper	N/A	27 tonne (30 ton)	1	0
23	Limestone Reclaim Feeder	Belt	100 tonne/h (110 tph)	1	0
24	Limestone Conveyor No. L2	Belt	100 tonne/h (110 tph)	1	0
25	Limestone Day Bin	w/ actuator	381 tonne (420 ton)	2	0

ACCOUNT 2 COAL AND SORBENT PREPARATION AND FEED

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	54 tonne/h (60 tph)	6	0
2	Coal Pulverizer	Ball type or equivalent	54 tonne/h (60 tph)	6	0
3	Limestone Weigh Feeder	Gravimetric	32 tonne/h (35 tph)	1	1
4	Limestone Ball Mill	Rotary	32 tonne/h (35 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	121,134 liters (32,000 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	490 lpm @ 12m H2O (540 gpm @ 40 ft H2O)	1	1
7	Hydroclone Classifier	4 active cyclones in a 5 cyclone bank	127 lpm (140 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1
9	Limestone Slurry Storage Tank with Agitator	Field erected	688,950 liters (182,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	345 lpm @ 9m H2O (380 gpm @ 30 ft H2O)	1	1

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	1,639,096 liters (433,000 gal)	2	0
2	Condensate Pumps	Vertical canned	22,334 lpm @ 335 m H2O (5,900 gpm @ 1,100 ft H2O)	1	1
3	Deaerator and Storage Tank	Horizontal spray type	2,730,629 kg/h (6,020,000 lb/h) 5 min. tank	1	0
4	Boiler Feed Pump and Steam Turbine Drive	Barrel type, multi-stage, centrifugal	45,804 lpm @ 2,499 m H2O (12,100 gpm @ 8,200 ft H2O)	1	1
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	13,628 lpm @ 2,499 m H2O (3,600 gpm @ 8,200 ft H2O)	1	0
6	LP Feedwater Heater 1A/1B	Horizontal U-tube	662,246 kg/h (1,460,000 lb/h)	2	0
7	LP Feedwater Heater 2A/2B	Horizontal U-tube	662,246 kg/h (1,460,000 lb/h)	2	0
8	LP Feedwater Heater 3A/3B	Horizontal U-tube	662,246 kg/h (1,460,000 lb/h)	2	0
9	LP Feedwater Heater 4A/4B	Horizontal U-tube	662,246 kg/h (1,460,000 lb/h)	2	0
10	HP Feedwater Heater 6	Horizontal U-tube	2,730,629 kg/h (6,020,000 lb/h)	1	0
11	HP Feedwater Heater 7	Horizontal U-tube	2,730,629 kg/h (6,020,000 lb/h)	1	0
12	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/h, 2.8 MPa, 343°C (40,000 lb/h, 400 psig, 650°F)	1	0
13	Fuel Oil System	No. 2 fuel oil for light off	1,135,632 liter (300,000 gal)	1	0
14	Service Air Compressors	Flooded Screw	28 m3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
15	Instrument Air Dryers	Duplex, regenerative	28 m3/min (1,000 scfm)	2	1
16	Closed Cycle Cooling Heat Exchangers	Shell and tube	53 MMkJ/h (50 MMBtu/h) each	2	0
17	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,820 lpm @ 30 m H2O (5,500 gpm @ 100 ft H2O)	2	1
18	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H2O (1,000 gpm @ 290 ft H2O)	1	1
19	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H2O (700 gpm @ 210 ft H2O)	1	1
20	Raw Water Pumps	Stainless steel, single suction	29,602 lpm @ 43 m H2O (7,820 gpm @ 140 ft H2O)	2	1
21	Filtered Water Pumps	Stainless steel, single suction	2,461 lpm @ 49 m H2O (650 gpm @ 160 ft H2O)	2	1
22	Filtered Water Tank	Vertical, cylindrical	2,377,257 liter (628,000 gal)	1	0
23	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	1,098 lpm (290 gpm)	1	1
24	Liquid Waste Treatment System	--	10 years, 24-hour storm	1	0

ACCOUNT 4 BOILER AND ACCESSORIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Subcritical, drum wall-fired, low NOx burners, overfire air	2,730,629 kg/h steam @ 16.5 MPa/566°C/566°C (6,020,000 lb/h steam @ 2,400 psig/1,050°F/1,050°F)	1	0
2	Primary Air Fan	Centrifugal	373,307 kg/h, 5,111 m3/min @ 123 cm WG (823,000 lb/h, 180,500 acfm @ 48 in. WG)	2	0
3	Forced Draft Fan	Centrifugal	1,215,629 kg/h, 16,642 m3/min @ 47 cm WG (2,680,000 lb/h, 587,700 acfm @ 19 in. WG)	2	0
4	Induced Draft Fan	Centrifugal	1,762,662 kg/h, 37,427 m3/min @ 90 cm WG (3,886,000 lb/h, 1,321,700 acfm @ 36 in. WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	3,524,417 kg/h (7,770,000 lb/h)	2	0
6	SCR Catalyst	--	--	3	0
7	Dilution Air Blower	Centrifugal	210 m3/min @ 108 cm WG (7,400 acfm @ 42 in. WG)	2	1
8	Ammonia Storage	Horizontal tank	230,912 liter (61,000 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	44 lpm @ 91 m H2O (12 gpm @ 300 ft H2O)	2	1

ACCOUNT 5 FLUE GAS CLEANUP

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Fabric Filter	Single stage, high-ratio with pulse-jet online cleaning system	1,762,662 kg/h (3,886,000 lb/h) 99.8% efficiency	2	0
2	Absorber Module	Counter-current open spray	59,607 m3/min (2,105,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	208,199 lpm @ 64 m H2O (55,000 gpm @ 210 ft H2O)	5	1
4	Bleed Pumps	Horizontal centrifugal	6,284 lpm (1,660 gpm) at 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	278 m3/min @ 0.3 MPa (9,800 acfm @ 42 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	1,590 lpm (420 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	50 tonne/h (55 tph) 50 wt % slurry	2	1
9	Filtrate Water Return Pumps	Horizontal centrifugal	946 lpm @ 12 m H2O (250 gpm @ 40 ft H2O)	1	1
10	Filtrate Water Return Storage Tank	Vertical, lined	643,525 lpm (170,000 gal)	1	0
11	Process Makeup Water Pumps	Horizontal centrifugal	3,861 lpm @ 21 m H2O (1,020 gpm @ 70 ft H2O)	1	1

ACCOUNT 5B CARBON DIOXIDE RECOVERY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Econamine FG Plus	Amine-based CO2 capture technology	1,890,575 kg/h (4,168,000 lb/h) 20.2 wt % CO2 inlet concentration	2	0
2	CO2 Compressor	Integrally geared, multi-stage centrifugal	344,408 kg/h @ 15.3 MPa (759,289 lb/h @ 2,215 psia)	2	0

ACCOUNT 6 COMBUSTION TURBINE/ACCESSORIES

N/A

ACCOUNT 7 HRSG, DUCTING & STACK

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	152 m (500 ft) high x 6.1 m (20 ft) diameter	1	0

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	720 MW 16.5 MPa/566°C/566°C (2400 psig/ 1050°F/1050°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	800 MVA @ 0.9 p.f., 24 kV, 60 Hz	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	2,551 MMkJ/h (2,420 MMBtu/h), Inlet water temperature 16ºC (60ºF), Water temperature rise 11ºC (20ºF)	1	0

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	704,092 lpm @ 30.5 m (186,000 gpm @ 100 ft)	4	2
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT 6,821 MMkJ/h (6,470 MMBtu/h) heat load	1	0

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Economizer Hopper (part of boiler scope of supply)	--	--	4	0
2	Bottom Ash Hopper (part of boiler scope of supply)	--	--	2	0
3	Clinker Grinder	--	6.4 tonne/h (7 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	--	--	6	0
5	Hydroejectors	--	--	12	
6	Economizer /Pyrites Transfer Tank	--	--	1	0
7	Ash Sluice Pumps	Vertical, wet pit	265 lpm @ 17 m H2O (70 gpm @ 56 ft H2O)	1	1
8	Ash Seal Water Pumps	Vertical, wet pit	7,571 lpm @ 9 m H2O (2000 gpm @ 28 ft H2O)	1	1
9	Hydrobins	--	265 lpm (70 gpm)	1	1
10	Baghouse Hopper (part of baghouse scope of supply)	--	--	24	0
11	Air Heater Hopper (part of boiler scope of supply)	--	--	10	0
12	Air Blower	--	23 m3/min @ 0.2 MPa (810 scfm @ 24 psi)	1	1
13	Fly Ash Silo	Reinforced concrete	771 tonne (1,700 ton)	2	0
14	Slide Gate Valves	--	--	2	0
15	Unloader	--	--	1	0
16	Telescoping Unloading Chute	--	136 tonne/h (150 tph)	1	0

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 650 MVA, 3-ph, 60 Hz	1	0
2	Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 140 MVA, 3-ph, 60 Hz	1	1
3	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 21 MVA, 3-ph, 60 Hz	1	1
4	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
5	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
6	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
7	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

ACCOUNT 12 INSTRUMENTATION AND CONTROL

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

4.2.10 CASE 10 – COST ESTIMATING

The cost estimating methodology was described previously in Section 2.6. Exhibit 4-22 shows the total plant capital cost summary organized by cost account and Exhibit 4-23 shows a more detailed breakdown of the capital costs. Exhibit 4-24 shows the initial and annual O&M costs.

The estimated TPC of the subcritical PC boiler with CO_2 capture is $2,888/kW. Process contingency represents 3.6 percent of the TPC and project contingency represents 12.6 percent. The 20-year LCOE, including CO_2 TS&M costs of 4.3 mills/kWh, is 118.8 mills/kWh.

Exhibit 4-22 Case 10 Total Plant Cost Summary

Client: USDOE/NETL **Report Date:** 09-May-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 10 - Subcritical PC w/ CO2
Plant Size: 549.6 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	$20,525	$5,540	$12,420	$0	$0	**$38,485**	$3,449	$0	$6,290	**$48,223**	$88
2	COAL & SORBENT PREP & FEED	$13,990	$807	$3,544	$0	$0	**$18,342**	$1,608	$0	$2,992	**$22,942**	$42
3	FEEDWATER & MISC. BOP SYSTEMS	$53,307	$0	$25,510	$0	$0	**$78,817**	$7,217	$0	$14,343	**$100,377**	$183
4	PC BOILER											
4.1	PC Boiler & Accessories	$167,758	$0	$108,417	$0	$0	**$276,176**	$26,774	$0	$30,295	**$333,245**	$606
4.2	SCR (w/4.1)	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.3	Open	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.4-4.9	Boiler BoP (w/ ID Fans)	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
	SUBTOTAL 4	**$167,758**	**$0**	**$108,417**	**$0**	**$0**	**$276,176**	**$26,774**	**$0**	**$30,295**	**$333,245**	**$606**
5	FLUE GAS CLEANUP	$109,618	$0	$37,721	$0	$0	**$147,340**	$14,000	$0	$16,134	**$177,474**	$323
5B	CO_2 REMOVAL & COMPRESSION	$243,432	$0	$74,100	$0	$0	**$317,532**	$30,138	$56,039	$80,742	**$484,450**	$881
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	N/A	$0	N/A	$0	$0	**$0**	$0	$0	$0	**$0**	$0
6.2-6.9	Combustion Turbine Other	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
	SUBTOTAL 6	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	N/A	$0	N/A	$0	$0	**$0**	$0	$0	$0	**$0**	$0
7.2-7.9	HRSG Accessories, Ductwork and Stack	$19,363	$1,062	$13,228	$0	$0	**$33,653**	$3,074	$0	$4,824	**$41,551**	$76
	SUBTOTAL 7	**$19,363**	**$1,062**	**$13,228**	**$0**	**$0**	**$33,653**	**$3,074**	**$0**	**$4,824**	**$41,551**	**$76**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$52,758	$0	$6,989	$0	$0	**$59,747**	$5,720	$0	$6,547	**$72,014**	$131
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$26,773	$1,170	$15,006	$0	$0	**$42,949**	$3,737	$0	$6,617	**$53,303**	$97
	SUBTOTAL 8	**$79,532**	**$1,170**	**$21,995**	**$0**	**$0**	**$102,697**	**$9,457**	**$0**	**$13,163**	**$125,317**	**$228**
9	COOLING WATER SYSTEM	$21,405	$11,272	$20,092	$0	$0	**$52,768**	$4,916	$0	$7,834	**$65,518**	$119
10	ASH/SPENT SORBENT HANDLING SYS	$5,440	$171	$7,234	$0	$0	**$12,844**	$1,223	$0	$1,448	**$15,515**	$28
11	ACCESSORY ELECTRIC PLANT	$20,789	$10,729	$30,669	$0	$0	**$62,187**	$5,554	$0	$8,642	**$76,384**	$139
12	INSTRUMENTATION & CONTROL	$9,150	$0	$9,615	$0	$0	**$18,765**	$1,718	$938	$2,635	**$24,056**	$44
13	IMPROVEMENTS TO SITE	$3,201	$1,840	$6,500	$0	$0	**$11,541**	$1,133	$0	$2,535	**$15,210**	$28
14	BUILDINGS & STRUCTURES	$0	$24,892	$23,781	$0	$0	**$48,672**	$4,385	$0	$7,959	**$61,016**	$111
	TOTAL COST	**$767,510**	**$57,483**	**$394,827**	**$0**	**$0**	**$1,219,819**	**$114,645**	**$56,977**	**$199,835**	**$1,591,277**	**$2,895**

Exhibit 4-23 Case 10 Total Plant Cost Details

Client: USDOE/NETL **Report Date:** 09-May-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 10 - Subcritical PC w/ CO2
Plant Size: 549.6 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	$4,213	$0	$1,944	$0	$0	$6,158	$550	$0	$1,006	$7,714	$14
1.2	Coal Stackout & Reclaim	$5,445	$0	$1,246	$0	$0	$6,692	$586	$0	$1,092	$8,369	$15
1.3	Coal Conveyors	$5,062	$0	$1,233	$0	$0	$6,296	$552	$0	$1,027	$7,875	$14
1.4	Other Coal Handling	$1,324	$0	$285	$0	$0	$1,610	$141	$0	$263	$2,013	$4
1.5	Sorbent Receive & Unload	$170	$0	$52	$0	$0	$221	$20	$0	$36	$277	$1
1.6	Sorbent Stackout & Reclaim	$2,741	$0	$508	$0	$0	$3,249	$283	$0	$530	$4,061	$7
1.7	Sorbent Conveyors	$978	$210	$242	$0	$0	$1,431	$124	$0	$233	$1,788	$3
1.8	Other Sorbent Handling	$591	$138	$313	$0	$0	$1,042	$92	$0	$170	$1,304	$2
1.9	Coal & Sorbent Hnd.Foundations	$0	$5,192	$6,596	$0	$0	$11,787	$1,102	$0	$1,933	$14,823	$27
	SUBTOTAL 1.	**$20,525**	**$5,540**	**$12,420**	**$0**	**$0**	**$38,485**	**$3,449**	**$0**	**$6,290**	**$48,223**	**$88**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	$2,458	$0	$484	$0	$0	$2,942	$257	$0	$480	$3,678	$7
2.2	Coal Conveyor to Storage	$6,292	$0	$1,388	$0	$0	$7,680	$672	$0	$1,253	$9,605	$17
2.3	Coal Injection System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.4	Misc.Coal Prep & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.5	Sorbent Prep Equipment	$4,677	$201	$981	$0	$0	$5,859	$510	$0	$955	$7,324	$13
2.6	Sorbent Storage & Feed	$563	$0	$218	$0	$0	$782	$69	$0	$128	$979	$2
2.7	Sorbent Injection System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.8	Booster Air Supply System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.9	Coal & Sorbent Feed Foundation	$0	$607	$473	$0	$0	$1,080	$99	$0	$177	$1,357	$2
	SUBTOTAL 2.	**$13,990**	**$807**	**$3,544**	**$0**	**$0**	**$18,342**	**$1,608**	**$0**	**$2,992**	**$22,942**	**$42**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	$20,059	$0	$7,016	$0	$0	$27,075	$2,376	$0	$4,418	$33,869	$62
3.2	Water Makeup & Pretreating	$8,410	$0	$2,704	$0	$0	$11,114	$1,042	$0	$2,431	$14,588	$27
3.3	Other Feedwater Subsystems	$6,624	$0	$2,810	$0	$0	$9,434	$841	$0	$1,541	$11,816	$21
3.4	Service Water Systems	$1,660	$0	$896	$0	$0	$2,556	$237	$0	$559	$3,352	$6
3.5	Other Boiler Plant Systems	$7,807	$0	$7,637	$0	$0	$15,444	$1,449	$0	$2,534	$19,426	$35
3.6	FO Supply Sys & Nat Gas	$271	$0	$333	$0	$0	$605	$56	$0	$99	$760	$1
3.7	Waste Treatment Equipment	$5,668	$0	$3,247	$0	$0	$8,915	$864	$0	$1,956	$11,734	$21
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	$2,808	$0	$865	$0	$0	$3,674	$353	$0	$805	$4,832	$9
	SUBTOTAL 3.	**$53,307**	**$0**	**$25,510**	**$0**	**$0**	**$78,817**	**$7,217**	**$0**	**$14,343**	**$100,377**	**$183**
4	PC BOILER											
4.1	PC Boiler & Accessories	$167,758	$0	$108,417	$0	$0	$276,176	$26,774	$0	$30,295	$333,245	$606
4.2	SCR (w/4.1)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.3	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.4	Boiler BoP (w/ ID Fans)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.5	Primary Air System	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.6	Secondary Air System	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.8	Major Component Rigging	$0	w/4.1	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.9	Boiler Foundations	$0	w/14.1	w/14.1	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 4.	**$167,758**	**$0**	**$108,417**	**$0**	**$0**	**$276,176**	**$26,774**	**$0**	**$30,295**	**$333,245**	**$606**

Exhibit 4-23 Case 10 Total Plant Cost Details (Continued)

Client: USDOE/NETL **Report Date:** 09-May-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 10 - Subcritical PC w/ CO2
Plant Size: 549.6 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5	FLUE GAS CLEANUP											
5.1	Absorber Vessels & Accessories	$75,926	$0	$16,357	$0	$0	$92,284	$8,734	$0	$10,102	$111,120	$202
5.2	Other FGD	$3,962	$0	$4,493	$0	$0	$8,456	$815	$0	$927	$10,197	$19
5.3	Bag House & Accessories	$22,462	$0	$14,266	$0	$0	$36,728	$3,513	$0	$4,024	$44,265	$81
5.4	Other Particulate Removal Materials	$1,520	$0	$1,628	$0	$0	$3,148	$303	$0	$345	$3,796	$7
5.5	Gypsum Dewatering System	$5,747	$0	$977	$0	$0	$6,724	$635	$0	$736	$8,096	$15
5.6	Mercury Removal System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5.9	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 5.	**$109,618**	**$0**	**$37,721**	**$0**	**$0**	**$147,340**	**$14,000**	**$0**	**$16,134**	**$177,474**	**$323**
5B	CO_2 REMOVAL & COMPRESSION											
5B.1	CO_2 Removal System	$214,986	$0	$65,208	$0	$0	$280,194	$26,593	$56,039	$72,565	$435,391	$792
5B.2	CO_2 Compression & Drying	$28,446	$0	$8,892	$0	$0	$37,338	$3,545	$0	$8,177	$49,059	$89
	SUBTOTAL 5B.	**$243,432**	**$0**	**$74,100**	**$0**	**$0**	**$317,532**	**$30,138**	**$56,039**	**$80,742**	**$484,450**	**$881**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
6.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.3	Compressed Air Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.9	Combustion Turbine Foundations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 6.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
7.2	HRSG Accessories	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$10,045	$0	$6,556	$0	$0	$16,601	$1,450	$0	$2,708	$20,758	$38
7.4	Stack	$9,318	$0	$5,457	$0	$0	$14,775	$1,412	$0	$1,619	$17,805	$32
7.9	Duct & Stack Foundations	$0	$1,062	$1,215	$0	$0	$2,278	$212	$0	$498	$2,988	$5
	SUBTOTAL 7.	**$19,363**	**$1,062**	**$13,228**	**$0**	**$0**	**$33,653**	**$3,074**	**$0**	**$4,824**	**$41,551**	**$76**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$52,758	$0	$6,989	$0	$0	$59,747	$5,720	$0	$6,547	$72,014	$131
8.2	Turbine Plant Auxiliaries	$375	$0	$804	$0	$0	$1,179	$114	$0	$129	$1,423	$3
8.3	Condenser & Auxiliaries	$6,425	$0	$2,475	$0	$0	$8,900	$847	$0	$975	$10,721	$20
8.4	Steam Piping	$19,973	$0	$9,866	$0	$0	$29,839	$2,490	$0	$4,849	$37,179	$68
8.9	TG Foundations	$0	$1,170	$1,861	$0	$0	$3,031	$285	$0	$663	$3,979	$7
	SUBTOTAL 8.	**$79,532**	**$1,170**	**$21,995**	**$0**	**$0**	**$102,697**	**$9,457**	**$0**	**$13,163**	**$125,317**	**$228**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$14,689	$0	$4,810	$0	$0	$19,499	$1,852	$0	$2,135	$23,485	$43
9.2	Circulating Water Pumps	$4,326	$0	$310	$0	$0	$4,636	$397	$0	$503	$5,536	$10
9.3	Circ.Water System Auxiliaries	$912	$0	$122	$0	$0	$1,034	$98	$0	$113	$1,245	$2
9.4	Circ.Water Piping	$0	$7,355	$7,015	$0	$0	$14,370	$1,324	$0	$2,354	$18,048	$33
9.5	Make-up Water System	$749	$0	$993	$0	$0	$1,742	$165	$0	$286	$2,193	$4
9.6	Component Cooling Water Sys	$728	$0	$575	$0	$0	$1,304	$122	$0	$214	$1,640	$3
9.9	Circ.Water System Foundations& Structures	$0	$3,917	$6,267	$0	$0	$10,185	$959	$0	$2,229	$13,372	$24
	SUBTOTAL 9.	**$21,405**	**$11,272**	**$20,092**	**$0**	**$0**	**$52,768**	**$4,916**	**$0**	**$7,834**	**$65,518**	**$119**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Ash Coolers	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.2	Cyclone Ash Letdown	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.3	HGCU Ash Letdown	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.4	High Temperature Ash Piping	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.5	Other Ash Recovery Equipment	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$723	$0	$2,231	$0	$0	$2,954	$288	$0	$324	$3,566	$6
10.7	Ash Transport & Feed Equipment	$4,716	$0	$4,801	$0	$0	$9,517	$900	$0	$1,042	$11,458	$21
10.8	Misc. Ash Handling Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.9	Ash/Spent Sorbent Foundation	$0	$171	$203	$0	$0	$373	$35	$0	$82	$490	$1
	SUBTOTAL 10.	**$5,440**	**$171**	**$7,234**	**$0**	**$0**	**$12,844**	**$1,223**	**$0**	**$1,448**	**$15,515**	**$28**

Exhibit 4-23 Case 10 Total Plant Cost Details (Continued)

Client:	USDOE/NETL
Project:	Bituminous Baseline Study
Case:	Case 10 - Subcritical PC w/ CO2
Plant Size:	549.6 MW,net
Estimate Type:	Conceptual
Report Date:	09-May-07
Cost Base (Dec)	2006 ($x1000)

TOTAL PLANT COST SUMMARY

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$1,672	$0	$274	$0	$0	$1,946	$180	$0	$159	$2,285	$4
11.2	Station Service Equipment	$4,842	$0	$1,658	$0	$0	$6,499	$622	$0	$534	$7,655	$14
11.3	Switchgear & Motor Control	$5,754	$0	$986	$0	$0	$6,740	$624	$0	$736	$8,100	$15
11.4	Conduit & Cable Tray	$0	$3,695	$12,573	$0	$0	$16,268	$1,557	$0	$2,674	$20,498	$37
11.5	Wire & Cable	$0	$6,702	$13,245	$0	$0	$19,947	$1,681	$0	$3,244	$24,872	$45
11.6	Protective Equipment	$253	$0	$898	$0	$0	$1,152	$113	$0	$126	$1,391	$3
11.7	Standby Equipment	$1,268	$0	$30	$0	$0	$1,298	$123	$0	$142	$1,563	$3
11.8	Main Power Transformers	$7,000	$0	$185	$0	$0	$7,185	$546	$0	$773	$8,504	$15
11.9	Electrical Foundations	$0	$332	$821	$0	$0	$1,153	$110	$0	$253	$1,515	$3
	SUBTOTAL 11.	**$20,789**	**$10,729**	**$30,669**	**$0**	**$0**	**$62,187**	**$5,554**	**$0**	**$8,642**	**$76,384**	**$139**
12	INSTRUMENTATION & CONTROL											
12.1	PC Control Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
12.3	Steam Turbine Control	w/8.1	$0	w/8.1	$0	$0	$0	$0	$0	$0	$0	$0
12.4	Other Major Component Control	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
12.5	Signal Processing Equipment	W/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.6	Control Boards,Panels & Racks	$469	$0	$292	$0	$0	$761	$73	$38	$131	$1,003	$2
12.7	Distributed Control System Equipment	$4,731	$0	$861	$0	$0	$5,592	$533	$280	$640	$7,045	$13
12.8	Instrument Wiring & Tubing	$2,613	$0	$5,301	$0	$0	$7,914	$674	$396	$1,348	$10,331	$19
12.9	Other I & C Equipment	$1,337	$0	$3,161	$0	$0	$4,498	$438	$225	$516	$5,677	$10
	SUBTOTAL 12.	**$9,150**	**$0**	**$9,615**	**$0**	**$0**	**$18,765**	**$1,718**	**$938**	**$2,635**	**$24,056**	**$44**
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation	$0	$54	$1,084	$0	$0	$1,138	$112	$0	$250	$1,500	$3
13.2	Site Improvements	$0	$1,786	$2,235	$0	$0	$4,022	$395	$0	$883	$5,300	$10
13.3	Site Facilities	$3,201	$0	$3,181	$0	$0	$6,382	$626	$0	$1,402	$8,410	$15
	SUBTOTAL 13.	**$3,201**	**$1,840**	**$6,500**	**$0**	**$0**	**$11,541**	**$1,133**	**$0**	**$2,535**	**$15,210**	**$28**
14	BUILDINGS & STRUCTURES											
14.1	Boiler Building	$0	$8,723	$7,774	$0	$0	$16,497	$1,481	$0	$2,697	$20,676	$38
14.2	Turbine Building	$0	$12,815	$12,103	$0	$0	$24,918	$2,244	$0	$4,074	$31,236	$57
14.3	Administration Building	$0	$613	$657	$0	$0	$1,270	$115	$0	$208	$1,592	$3
14.4	Circulation Water Pumphouse	$0	$281	$227	$0	$0	$508	$45	$0	$83	$636	$1
14.5	Water Treatment Buildings	$0	$1,110	$926	$0	$0	$2,036	$182	$0	$333	$2,551	$5
14.6	Machine Shop	$0	$410	$279	$0	$0	$689	$61	$0	$113	$863	$2
14.7	Warehouse	$0	$278	$282	$0	$0	$560	$51	$0	$92	$702	$1
14.8	Other Buildings & Structures	$0	$227	$196	$0	$0	$423	$38	$0	$69	$530	$1
14.9	Waste Treating Building & Str.	$0	$435	$1,336	$0	$0	$1,771	$167	$0	$291	$2,229	$4
	SUBTOTAL 14.	**$0**	**$24,892**	**$23,781**	**$0**	**$0**	**$48,672**	**$4,385**	**$0**	**$7,959**	**$61,016**	**$111**
	TOTAL COST	**$767,510**	**$57,483**	**$394,827**	**$0**	**$0**	**$1,219,819**	**$114,645**	**$56,977**	**$199,835**	**$1,591,277**	**$2,895**

Exhibit 4-24 Case 10 Initial and Annual Operating and Maintenance Costs

INITIAL & ANNUAL O&M EXPENSES						Cost Base (Dec)	2006
Case 10 - Subcritical PC w/ CO2						Heat Rate-net(Btu/kWh):	13,724
						MWe-net:	550
						Capacity Factor: (%):	85
OPERATING & MAINTENANCE LABOR							
Operating Labor							
Operating Labor Rate(base):	33.00	$/hour					
Operating Labor Burden:	30.00	% of base					
Labor O-H Charge Rate:	25.00	% of labor					
			Total				
Skilled Operator	2.0		2.0				
Operator	11.3		11.3				
Foreman	1.0		1.0				
Lab Tech's, etc.	2.0		2.0				
TOTAL-O.J.'s	16.3		16.3				
						Annual Cost $	Annual Unit Cost $/kW-net
Annual Operating Labor Cost						$6,138,007	$11.168
Maintenance Labor Cost						$10,295,213	$18.732
Administrative & Support Labor						$4,108,305	$7.475
TOTAL FIXED OPERATING COSTS						**$20,541,525**	**$37.375**
VARIABLE OPERATING COSTS							
							$/kWh-net
Maintenance Material Cost						**$15,442,820**	**$0.00377**
Consumables	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost			
Water(/1000 gallons)	0	10,151	1.03	**$0**		**$3,243,688**	**$0.00079**
Chemicals							
MU & WT Chem.(lb)	343,946	49,135	0.16	$56,682		$2,512,244	$0.00061
Limestone (ton)	5,372	767	20.60	$110,669		$4,905,029	$0.00120
Carbon (Mercury Removal) (lb)	0	0	0.00	$0		$0	$0.00000
MEA Solvent (ton)	1,174	1.67	2,142.40	$2,515,178		$1,108,686	$0.00027
NaOH (tons)	82	8.18	412.96	$33,863		$1,048,541	$0.00026
H2SO4 (tons)	79	7.91	132.15	$10,440		$324,224	$0.00008
Corrosion Inhibitor	0	0	0.00	$162,300		$7,730	$0.00000
Activated Carbon(lb)	0	1,992	1.00	$0		$618,018	$0.00015
Ammonia (28% NH3) ton	813	116	123.60	$100,439		$4,451,615	$0.00109
Subtotal Chemicals				**$2,989,571**		**$14,976,086**	**$0.00366**
Other							
Supplemental Fuel(MBtu)	0	0	0.00	$0		$0	$0.00000
SCR Catalyst(m3)	w/equip.	0.68	5,500.00	$0		$1,168,014	$0.00029
Emission Penalties	0	0	0.00	$0		$0	$0.00000
Subtotal Other				**$0**		**$1,168,014**	**$0.00029**
Waste Disposal							
Flyash (ton)	0	144	15.45	$0		$690,819	$0.00017
Bottom Ash(ton)	0	577	15.45	$0		$2,763,393	$0.00068
Subtotal-Waste Disposal				**$0**		**$3,454,212**	**$0.00084**
By-products & Emissions							
Gypsum (tons)	0	1,196	0.00	$0		$0	$0.00000
Subtotal By-Products				**$0**		**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$2,989,571**		**$38,284,819**	**$0.00936**
Fuel(ton)	232,764	7,759	42.11	**$9,801,707**		**$101,365,989**	**$0.02477**

4.3 SUPERCRITICAL PC CASES

This section contains an evalution of plant designs for Cases 11 and 12 which are based on a supercritical PC plant with a nominal net output of 550 MWe. Both plants use a single reheat 24.1 MPa/593°C/593°C (3500 psig/1100°F/1100°F) cycle. The only difference between the two plants is that Case 12 includes CO_2 capture while Case 11 does not.

The balance of Section 4.3 is organized in an analogous manner to the subcrtical PC section:

- Process and System Description for Case 11
- Key Assumptions for Cases 11 and 12
- Sparing Philosophy for Cases 11 and 12
- Performance Results for Case 11
- Equipment List for Case 11
- Cost Estimates for Case 11
- Process and System Description, Performance Results, Equipment List and Cost Estimates for Case 12

4.3.1 PROCESS DESCRIPTION

In this section the supercritical PC process without CO_2 capture is described. The system description is nearly identical to the subcritical PC case without CO_2 capture but is repeated here for completeness. The description follows the block flow diagram (BFD) in Exhibit 4-25 and stream numbers reference the same Exhibit. The tables in Exhibit 4-26 provide process data for the numbered streams in the BFD.

Coal (stream 6) and primary air (stream 4) are introduced into the boiler through the wall-fired burners. Additional combustion air, including the overfire air, is provided by the forced draft fans (stream 2). The boiler operates at a slight negative pressure so air leakage is into the boiler, and the infiltration air is accounted for in stream 5.

Flue gas exits the boiler through the SCR reactor (stream 8) and is cooled to 177°C (350°F) in the combustion air preheater (not shown) before passing through a fabric filter for particulate removal (stream 10). An ID fan increases the flue gas temperature to 188°C (370°F) and provides the motive force for the flue gas (stream 11) to pass through the FGD unit. FGD inputs and outputs include makeup water (stream 13), oxidation air (stream 14), limestone slurry (stream 12) and product gypsum (stream 15). The clean, saturated flue gas exiting the FGD unit (stream 16) passes to the plant stack and is discharged to atmosphere

Exhibit 4-25 Case 11 Process Flow Diagram, Supercritical Unit without CO_2 Capture

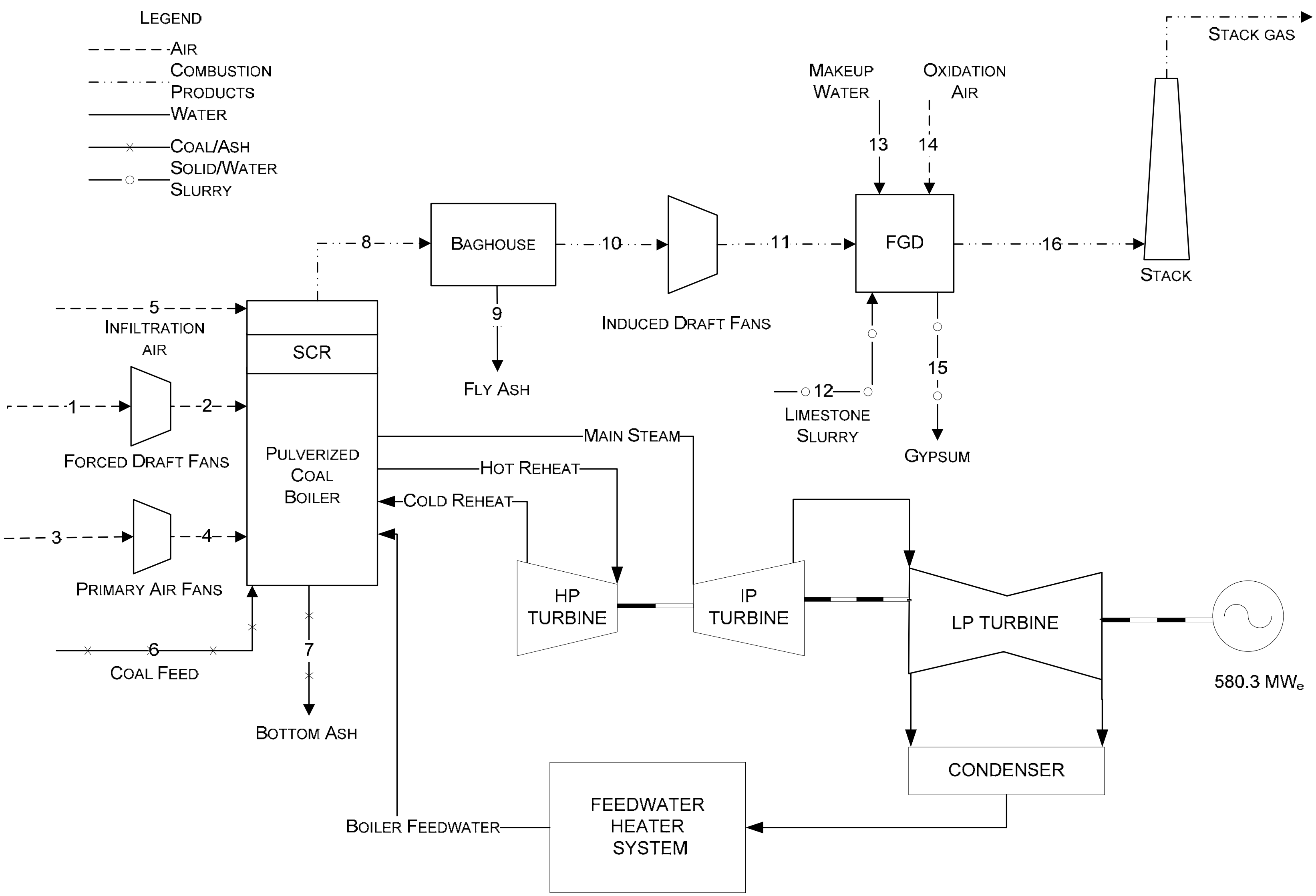

Exhibit 4-26 Case 11 Stream Table, Supercritical Unit without CO_2 Capture

	1	2	3	4	5	6	7	8
V-L Mole Fractions								
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0087
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.1450
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	0.0870
N_2	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.7324
O_2	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0247
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021
Total	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000
V-L Flow (lb_{mol}/hr)	107,211	107,211	32,934	32,934	2,477	0	0	150,861
V-L Flow (lb/hr)	3,093,780	3,093,780	950,376	950,376	71,480	0	0	4,487,030
Solids Flowrate	0	0	0	0	0	411,282	7,976	31,905
Temperature (°F)	59	66	59	78	59	59	350	350
Pressure (psia)	14.70	15.25	14.70	16.14	14.70	14.70	14.40	14.40
Enthalpy (BTU/lb)[A]	13.1	14.9	13.1	17.7	13.1	11,676	51.4	135.6
Density (lb/ft^3)	0.08	0.08	0.08	0.08	0.08	---	---	0.05
Avg. Molecular Weight	28.86	28.86	28.86	28.86	28.86	---	---	29.74

	9	10	11	12	13	14	15	16
V-L Mole Fractions								
Ar	0.0000	0.0087	0.0087	0.0000	0.0000	0.0092	0.0000	0.0080
CO_2	0.0000	0.1450	0.1450	0.0000	0.0000	0.0003	0.0016	0.1326
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0000	0.0870	0.0870	1.0000	1.0000	0.0099	0.9976	0.1669
N_2	0.0000	0.7324	0.7324	0.0000	0.0000	0.7732	0.0008	0.6690
O_2	0.0000	0.0247	0.0247	0.0000	0.0000	0.2074	0.0000	0.0235
SO_2	0.0000	0.0021	0.0021	0.0000	0.0000	0.0000	0.0000	0.0000
Total	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flow (lb_{mol}/hr)	0	150,861	150,861	5,111	24,381	1,705	14,140	167,129
V-L Flow (lb/hr)	0	4,487,030	4,487,030	92,067	439,223	49,200	255,432	4,789,380
Solids Flowrate	31,905	0	0	40,819	0	0	63,529	0
Temperature (°F)	350	350	370	59	60	59	134	134
Pressure (psia)	14.20	14.20	15.26	14.70	14.70	14.70	14.70	14.70
Enthalpy (BTU/lb)[A]	51.4	136.2	141.5	---	33.3	13.1	87.0	139.1
Density (lb/ft^3)	---	0.05	0.05	62.62	62.59	0.08	36.10	0.07
Avg. Molecular Weight	---	29.74	29.74	18.02	18.02	28.86	18.06	28.66

A - Reference conditions are 32.02 F & 0.089 PSIA

4.3.2 KEY SYSTEM ASSUMPTIONS

System assumptions for Cases 11 and 12, supercritical PC with and without CO_2 capture, are compiled in Exhibit 4-27.

Exhibit 4-27 Supercritical PC Plant Study Configuration Matrix

	Case 11 w/o CO_2 Capture	Case 12 w/CO_2 Capture
Steam Cycle, MPa/°C/°C (psig/°F/°F)	24.1/593/593 (3500/1100/1100)	24.1/593/593 (3500/1100/1100)
Coal	Illinois No. 6	Illinois No. 6
Condenser pressure, mm Hg (in Hg)	50.8 (2)	50.8 (2)
Boiler Efficiency, %	89	89
Cooling water to condenser, °C (ºF)	16 (60)	16 (60)
Cooling water from condenser, °C (ºF)	27 (80)	27 (80)
Stack temperature, °C (°F)	57 (135)	32 (89)
SO_2 Control	Wet Limestone Forced Oxidation	Wet Limestone Forced Oxidation
FGD Efficiency, % (A)	98	98 (B, C)
NOx Control	LNB w/OFA and SCR	LNB w/OFA and SCR
SCR Efficiency, % (A)	86	86
Ammonia Slip (end of catalyst life), ppmv	2	2
Particulate Control	Fabric Filter	Fabric Filter
Fabric Filter efficiency, % (A)	99.8	99.8
Ash Distribution, Fly/Bottom	80% / 20%	80% / 20%
Mercury Control	Co-benefit Capture	Co-benefit Capture
Mercury removal efficiency, % (A)	90	90
CO_2 Control	N/A	Econamine FG Plus
CO_2 Capture, % (A)	N/A	90
CO_2 Sequestration	N/A	Off-site Saline Formation

A. Removal efficiencies are based on the flue gas content

B. An SO_2 polishing step is included to meet more stringent SOx content limits in the flue gas (< 10 ppmv) to reduce formation of amine heat stable salts during the CO_2 absorption process

C. SO_2 exiting the post-FGD polishing step is absorbed in the CO_2 capture process making stack emissions negligible

Balance of Plant – Cases 11 and 12

The balance of plant assumptions are common to all cases and were presented previously in Exhibit 4-6.

4.3.3 SPARING PHILOSOPHY

Single trains are used throughout the design with exceptions where equipment capacity requires an additional train. There is no redundancy other than normal sparing of rotating equipment. The plant design consists of the following major subsystems:

- One dry-bottom, wall-fired PC supercritical boiler (1 x 100%)
- Two SCR reactors (2 x 50%)
- Two single-stage, in-line, multi-compartment fabric filters (2 x 50%)
- One wet limestone forced oxidation positive pressure absorber (1 x 100%)
- One steam turbine (1 x 100%)
- For Case 12 only, two parallel Econamine FG Plus CO_2 absorption systems, with each system consisting of two absorbers, strippers and ancillary equipment (2 x 50%)

4.3.4 CASE 11 PERFORMANCE RESULTS

The plant produces a net output of 550 MWe at a net plant efficiency of 39.1 percent (HHV basis).

Overall performance for the plant is summarized in Exhibit 4-28 which includes auxiliary power requirements.

Exhibit 4-28 Case 11 Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
TOTAL (STEAM TURBINE) POWER, kWe	**580,260**
AUXILIARY LOAD SUMMARY, kWe (Note 1)	
Coal Handling and Conveying	410
Limestone Handling & Reagent Preparation	890
Pulverizers	2,800
Ash Handling	530
Primary Air Fans	1,310
Forced Draft Fans	1,660
Induced Draft Fans	7,130
SCR	50
Baghouse	100
FGD Pumps and Agitators	2,980
Econamine FG Plus Auxiliaries	N/A
CO_2 Compression	N/A
Miscellaneous Balance of Plant (Note 2)	2,000
Steam Turbine Auxiliaries	400
Condensate Pumps	790
Circulating Water Pumps	4,770
Cooling Tower Fans	2,460
Transformer Loss	1,830
TOTAL AUXILIARIES, kWe	**30,110**
NET POWER, kWe	**550,150**
Net Plant Efficiency (HHV)	39.1%
Net Plant Heat Rate (Btu/kWh)	8,721
CONDENSER COOLING DUTY, 10^6 kJ/h (10^6 Btu/h)	2,314 (2,195)
CONSUMABLES	
As-Received Coal Feed, kg/h (lb/h)	186,555 (411,282)
Limestone Sorbent Feed, kg/h (lb/h)	18,515 (40,819)
Thermal Input, kWt	1,406,161
Makeup Water, m^3/min (gpm)	20.6 (5,441)

Notes: 1. Boiler feed pumps are steam turbine driven
2. Includes plant control systems, lighting, HVAC and miscellanous low voltage loads

Environmental Performance

The environmental targets for emissions of Hg, NOx, SO_2 and particulate matter were presented in Section 2.4. A summary of the plant air emissions for Case 11 is presented in Exhibit 4-29.

Exhibit 4-29 Case 11 Air Emissions

	kg/GJ ($lb/10^6$ Btu)	Tonne/year (ton/year) 85% capacity factor	kg/MWh (lb/MWh)
SO_2	0.036 (0.085)	1,373 (1,514)	0.318 (0.701)
NO_X	0.030 (0.070)	1,134 (1,250)	0.263 (0.579)
Particulates	0.006 (0.013)	211 (232)	0.049 (0.107)
Hg	0.49×10^{-6} (1.14×10^{-6})	0.018 (0.020)	4.3×10^{-6} (9.4×10^{-6})
CO_2	87.5 (203)	3,295,000 (3,632,000)	763 (1,681)
CO_2[1]			804 (1,773)

[1] CO_2 emissions based on net power instead of gross power

SO_2 emissions are controlled using a wet limestone forced oxidation scrubber that achieves a removal efficiency of 98 percent. The byproduct calcium sulfate is dewatered and stored on site. The wallboard grade material can potentially be marketed and sold, but since it is highly dependent on local market conditions, no byproduct credit was taken. The saturated flue gas exiting the scrubber is vented through the plant stack.

NOx emissions are controlled to about 0.5 $lb/10^6$ Btu through the use of LNBs and OFA. An SCR unit then further reduces the NOx concentration by 86 percent to 0.07 $lb/10^6$ Btu.

Particulate emissions are controlled using a pulse jet fabric filter which operates at an efficiency of 99.8 percent.

Co-benefit capture results in a 90 percent reduction of mercury emissions. CO_2 emissions represent the uncontrolled discharge from the process.

Exhibit 4-30 shows the overall water balance for the plant. Raw water is obtained from groundwater (50 percent) and from municipal sources (50 percent). The water usage represents only the contribution of raw water makeup. In some cases the water demand is greater than raw water makeup because of internal water recycle streams. For example, the boiler feedwater blowdown stream is re-used as makeup to the cooling tower, thus reducing the raw water requirement by that amount.

Exhibit 4-30 Case 11 Water Balance

Water Use	Water Demand, m^3/min (gpm)	Internal Recycle, m^3/min (gpm)	Raw Water Makeup, m^3/min (gpm)
FGD Makeup	2.1 (546)	0	2.1 (546)
BFW Makeup	0.3 (73)	0	0.3 (73)
Cooling Tower Makeup	18.5 (4,895)	0.3 (73)	18.2 (4,822)
Total	**20.9 (5,514)**	**0.3 (73)**	**20.6 (5,441)**

Heat and Mass Balance Diagrams

A heat and mass balance diagram is shown for the Case 11 PC boiler, the FGD unit and steam cycle in Exhibit 4-31.

An overall plant energy balance is provided in tabular form in Exhibit 4-32. The power out is the steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 4-28) is calculated by multiplying the power out by a generator efficiency of 98.4 percent.

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Exhibit 4-31 Case 11 Heat and Mass Balance, Supercritical PC Boiler without CO_2 Capture

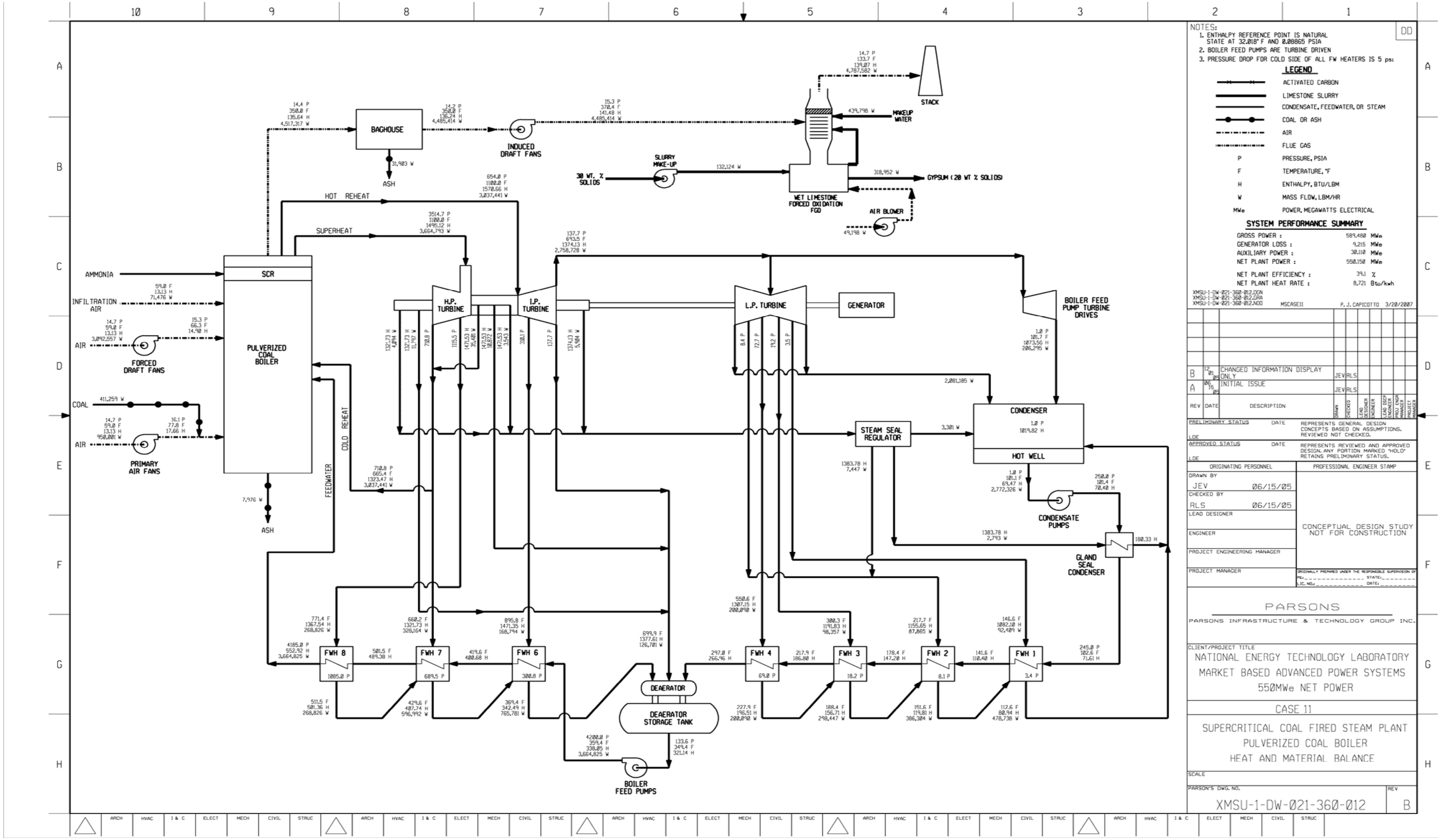

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Exhibit 4-32 Case 11 Overall Energy Balance (0°C [32°F] Reference)

	HHV	Sensible + Latent	Power	Total
Heat In (MMBtu/hr)				
Coal	4,798.0	4.0		4,802.0
Ambient Air		53.1		53.1
Infiltration Air		0.9		0.9
Limestone		61.0		61.0
FGD Oxidant		0.6		0.6
Water		17.6		17.6
Auxiliary Power			102.0	102.0
Totals	**4,798.0**	**137.3**	**102.0**	**5,037.3**
Heat Out (MMBtu/hr)				
Bottom Ash		0.4		0.4
Fly Ash		1.6		1.6
Flue Gas Exhaust		666.1		666.1
Gypsum Slurry		27.7		27.7
Condenser		2,195.0		2,195.0
Process Losses (1)		135.1		135.1
Power			2,011.4	2,011.4
Totals	**0.0**	**3,025.9**	**2,011.4**	**5,037.3**

(1) Process Losses are calculated by difference and reflect various boiler, turbine, and other heat and work losses. Aspen flowsheet balance is within 0.5 percent.

4.3.5 CASE 11 – MAJOR EQUIPMENT LIST

Major equipment items for the supercritical PC plant with no CO_2 capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 4.3.6. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

ACCOUNT 1 FUEL AND SORBENT HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	181 tonne (200 ton)	2	0
2	Feeder	Belt	572 tonne/h (630 tph)	2	0
3	Conveyor No. 1	Belt	1,134 tonne/h (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,134 tonne/h (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,134 tonne/h (1,250 tph)	1	0
8	Reclaim Hopper	N/A	36 tonne (40 ton)	2	1
9	Feeder	Vibratory	154 tonne/h (170 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	308 tonne/h (340 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	154 tonne (170 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3" x 0 - 1-1/4" x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	308 tonne/h (340 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	308 tonne/h (340 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	726 tonne (800 ton)	3	0
19	Limestone Truck Unloading Hopper	N/A	36 tonne (40 ton)	1	0
20	Limestone Feeder	Belt	82 tonne/h (90 tph)	1	0
21	Limestone Conveyor No. L1	Belt	82 tonne/h (90 tph)	1	0
22	Limestone Reclaim Hopper	N/A	18 tonne (20 ton)	1	0
23	Limestone Reclaim Feeder	Belt	64 tonne/h (70 tph)	1	0
24	Limestone Conveyor No. L2	Belt	64 tonne/h (70 tph)	1	0
25	Limestone Day Bin	w/ actuator	245 tonne (270 ton)	2	0

ACCOUNT 2 COAL AND SORBENT PREPARATION AND FEED

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	36 tonne/h (40 tph)	6	0
2	Coal Pulverizer	Ball type or equivalent	36 tonne/h (40 tph)	6	0
3	Limestone Weigh Feeder	Gravimetric	20 tonne/h (22 tph)	1	1
4	Limestone Ball Mill	Rotary	20 tonne/h (22 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	75,709 liters (20,000 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	308 lpm @ 12m H2O (340 gpm @ 40 ft H2O)	1	1
7	Hydroclone Classifier	4 active cyclones in a 5 cyclone bank	82 lpm (90 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1
9	Limestone Slurry Storage Tank with Agitator	Field erected	439,111 liters (116,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	218 lpm @ 9m H2O (240 gpm @ 30 ft H2O)	1	1

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	1,097,778 liters (290,000 gal)	2	0
2	Condensate Pumps	Vertical canned	23,091 lpm @ 213 m H2O (6,100 gpm @ 700 ft H2O)	1	1
3	Deaerator and Storage Tank	Horizontal spray type	1,828,433 kg/h (4,031,000 lb/h) 5 min. tank	1	0
4	Boiler Feed Pump and Steam Turbine Drive	Barrel type, multi-stage, centrifugal	30,662 lpm @ 3,475 m H2O (8,100 gpm @ 11,400 ft H2O)	1	1
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	9,085 lpm @ 3,475 m H2O (2,400 gpm @ 11,400 ft H2O)	1	0
6	LP Feedwater Heater 1A/1B	Horizontal U-tube	689,461 kg/h (1,520,000 lb/h)	2	0
7	LP Feedwater Heater 2A/2B	Horizontal U-tube	689,461 kg/h (1,520,000 lb/h)	2	0
8	LP Feedwater Heater 3A/3B	Horizontal U-tube	689,461 kg/h (1,520,000 lb/h)	2	0
9	LP Feedwater Heater 4A/4B	Horizontal U-tube	689,461 kg/h (1,520,000 lb/h)	2	0
10	HP Feedwater Heater 6	Horizontal U-tube	1,827,979 kg/h (4,030,000 lb/h)	1	0
11	HP Feedwater Heater 7	Horizontal U-tube	1,827,979 kg/h (4,030,000 lb/h)	1	0
12	HP Feedwater heater 8	Horizontal U-tube	1,827,979 kg/h (4,030,000 lb/h)	1	0
13	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/h, 2.8 MPa, 343°C (40,000 lb/h, 400 psig, 650°F)	1	0
14	Fuel Oil System	No. 2 fuel oil for light off	1,135,632 liter (300,000 gal)	1	0
15	Service Air Compressors	Flooded Screw	28 m3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
16	Instrument Air Dryers	Duplex, regenerative	28 m3/min (1,000 scfm)	2	1
17	Closed Cycle Cooling Heat Exchangers	Shell and tube	53 MMkJ/h (50 MMBtu/h) each	2	0
18	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,820 lpm @ 30 m H2O (5,500 gpm @ 100 ft H2O)	2	1
19	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H2O (1,000 gpm @ 290 ft H2O)	1	1
20	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H2O (700 gpm @ 210 ft H2O)	1	1
21	Raw Water Pumps	Stainless steel, single suction	11,470 lpm @ 43 m H2O (3,030 gpm @ 140 ft H2O)	2	1
22	Filtered Water Pumps	Stainless steel, single suction	1,438 lpm @ 49 m H2O (380 gpm @ 160 ft H2O)	2	1
23	Filtered Water Tank	Vertical, cylindrical	1,377,901 liter (364,000 gal)	1	0
24	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	606 lpm (160 gpm)	1	1
25	Liquid Waste Treatment System	--	10 years, 24-hour storm	1	0

ACCOUNT 4 BOILER AND ACCESSORIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Supercritical, drum, wall-fired, low NOx burners, overfire air	1,827,979 kg/h steam @ 24.1 MPa/593°C/593°C (4,030,000 lb/h steam @ 3,500 psig/1,100°F/1,100°F)	1	0
2	Primary Air Fan	Centrifugal	237,229 kg/h, 3,245 m3/min @ 123 cm WG (523,000 lb/h, 114,600 acfm @ 48 in. WG)	2	0
3	Forced Draft Fan	Centrifugal	772,015 kg/h, 10,568 m3/min @ 47 cm WG (1,702,000 lb/h, 373,200 acfm @ 19 in. WG)	2	0
4	Induced Draft Fan	Centrifugal	1,119,467 kg/h, 23,769 m3/min @ 90 cm WG (2,468,000 lb/h, 839,400 acfm @ 36 in. WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	2,240,749 kg/h (4,940,000 lb/h)	2	0
6	SCR Catalyst	--	--	3	0
7	Dilution Air Blower	Centrifugal	133 m3/min @ 108 cm WG (4,700 acfm @ 42 in. WG)	2	1
8	Ammonia Storage	Horizontal tank	147,632 liter (39,000 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	28 lpm @ 91 m H2O (7 gpm @ 300 ft H2O)	2	1

ACCOUNT 5 FLUE GAS CLEANUP

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Fabric Filter	Single stage, high-ratio with pulse-jet online cleaning system	1,119,467 kg/h (2,468,000 lb/h) 99.8% efficiency	2	0
2	Absorber Module	Counter-current open spray	37,662 m3/min (1,330,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	132,490 lpm @ 64 m H2O (35,000 gpm @ 210 ft H2O)	5	1
4	Bleed Pumps	Horizontal centrifugal	4,013 lpm (1,060 gpm) at 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	168 m3/min @ 0.3 MPa (5,930 acfm @ 42 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	1,022 lpm (270 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	32 tonne/h (35 tph) 50 wt % slurry	2	1
9	Filtrate Water Return Pumps	Horizontal centrifugal	606 lpm @ 12 m H2O (160 gpm @ 40 ft H2O)	1	1
10	Filtrate Water Return Storage Tank	Vertical, lined	416,399 lpm (110,000 gal)	1	0
11	Process Makeup Water Pumps	Horizontal centrifugal	2,271 lpm @ 21 m H2O (600 gpm @ 70 ft H2O)	1	1

ACCOUNT 6 COMBUSTION TURBINE/ACCESSORIES

N/A

ACCOUNT 7 HRSG, DUCTING & STACK

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	152 m (500 ft) high x 5.8 m (19 ft) diameter	1	0

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	610 MW 24.1 MPa/593°C/593°C (3500 psig/ 1100°F/1100°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	680 MVA @ 0.9 p.f., 24 kV, 60 Hz	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	2,541 MMkJ/h (2,410 MMBtu/h), Inlet water temperature 16ºC (60ºF), Water temperature rise 11ºC (20ºF)	1	0

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	476,966 lpm @ 30.5 m (126,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT 2,657 MMkJ/h (2,520 MMBtu/h) heat load	1	0

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Economizer Hopper (part of boiler scope of supply)	--	--	4	0
2	Bottom Ash Hopper (part of boiler scope of supply)	--	--	2	0
3	Clinker Grinder	--	3.6 tonne/h (4 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	--	--	6	0
5	Hydroejectors	--	--	12	
6	Economizer /Pyrites Transfer Tank	--	--	1	0
7	Ash Sluice Pumps	Vertical, wet pit	151 lpm @ 17 m H2O (40 gpm @ 56 ft H2O)	1	1
8	Ash Seal Water Pumps	Vertical, wet pit	7,571 lpm @ 9 m H2O (2000 gpm @ 28 ft H2O)	1	1
9	Hydrobins	--	151 lpm (40 gpm)	1	1
10	Baghouse Hopper (part of baghouse scope of supply)	--	--	24	0
11	Air Heater Hopper (part of boiler scope of supply)	--	--	10	0
12	Air Blower	--	14 m3/min @ 0.2 MPa (510 scfm @ 24 psi)	1	1
13	Fly Ash Silo	Reinforced concrete	499 tonne (1,100 ton)	2	0
14	Slide Gate Valves	--	--	2	0
15	Unloader	--	--	1	0
16	Telescoping Unloading Chute	--	91 tonne/h (100 tph)	1	0

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 640 MVA, 3-ph, 60 Hz	1	0
2	Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 10 MVA, 3-ph, 60 Hz	1	1
3	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 5 MVA, 3-ph, 60 Hz	1	1
4	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
5	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
6	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
7	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

ACCOUNT 12 INSTRUMENTATION AND CONTROL

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

4.3.6 CASE 11 – COSTS ESTIMATING RESULTS

The cost estimating methodology was described previously in Section 2.6. Exhibit 4-33 shows the total plant capital cost summary organized by cost account and Exhibit 4-34 shows a more detailed breakdown of the capital costs. Exhibit 4-35 shows the initial and annual O&M costs.

The estimated TPC of the supercritical PC boiler with no CO_2 capture is $1,574/kW. No process contingency was included in this case because all elements of the technology are commercially proven. The project contingency is 10.7 percent of the TPC. The 20-year LCOE is 63.3 mills/kWh.

Exhibit 4-33 Case 11 Total Plant Cost Summary

Client:	USDOE/NETL
Project:	Bituminous Baseline Study
Report Date:	09-May-07

TOTAL PLANT COST SUMMARY

Case:	Case 11 - Supercritical PC w/o CO2
Plant Size:	550.2 MW,net
Estimate Type:	Conceptual
Cost Base (Dec)	2006 ($x1000)

Acct		Equipment	Material	Labor		Sales	Bare Erected	Eng'g CM	Contingencies		TOTAL PLANT COST	
No.	Item/Description	Cost	Cost	Direct	Indirect	Tax	Cost $	H.O.& Fee	Process	Project	$	$/kW
1	COAL & SORBENT HANDLING	$15,481	$4,183	$9,376	$0	$0	**$29,040**	$2,602	$0	$4,746	**$36,389**	$66
2	COAL & SORBENT PREP & FEED	$10,405	$603	$2,638	$0	$0	**$13,646**	$1,196	$0	$2,226	**$17,068**	$31
3	FEEDWATER & MISC. BOP SYSTEMS	$40,107	$0	$18,856	$0	$0	**$58,963**	$5,369	$0	$10,462	**$74,795**	$136
4	PC BOILER											
4.1	PC Boiler & Accessories	$148,766	$0	$83,888	$0	$0	**$232,654**	$22,535	$0	$25,519	**$280,708**	$510
4.2	SCR (w/4.1)	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.3	Open	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.4-4.9	Boiler BoP (w/ ID Fans)	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
	SUBTOTAL 4	**$148,766**	**$0**	**$83,888**	**$0**	**$0**	**$232,654**	**$22,535**	**$0**	**$25,519**	**$280,708**	**$510**
5	FLUE GAS CLEANUP	$78,075	$0	$26,700	$0	$0	**$104,775**	$9,955	$0	$11,473	**$126,203**	$229
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	N/A	$0	N/A	$0	$0	**$0**	$0	$0	$0	**$0**	$0
6.2-6.9	Combustion Turbine Other	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
	SUBTOTAL 6	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	N/A	$0	N/A	$0	$0	**$0**	$0	$0	$0	**$0**	$0
7.2-7.9	HRSG Accessories, Ductwork and Stack	$16,653	$959	$11,402	$0	$0	**$29,013**	$2,656	$0	$4,132	**$35,801**	$65
	SUBTOTAL 7	**$16,653**	**$959**	**$11,402**	**$0**	**$0**	**$29,013**	**$2,656**	**$0**	**$4,132**	**$35,801**	**$65**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$48,728	$0	$6,532	$0	$0	**$55,260**	$5,291	$0	$6,055	**$66,606**	$121
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$23,094	$1,042	$12,656	$0	$0	**$36,792**	$3,213	$0	$5,619	**$45,625**	$83
	SUBTOTAL 8	**$71,822**	**$1,042**	**$19,188**	**$0**	**$0**	**$92,052**	**$8,504**	**$0**	**$11,675**	**$112,231**	**$204**
9	COOLING WATER SYSTEM	$11,816	$6,553	$11,613	$0	$0	**$29,981**	$2,799	$0	$4,503	**$37,283**	$68
10	ASH/SPENT SORBENT HANDLING SYS	$4,232	$133	$5,628	$0	$0	**$9,992**	$951	$0	$1,126	**$12,069**	$22
11	ACCESSORY ELECTRIC PLANT	$15,533	$5,832	$17,190	$0	$0	**$38,556**	$3,411	$0	$5,217	**$47,183**	$86
12	INSTRUMENTATION & CONTROL	$8,069	$0	$8,480	$0	$0	**$16,549**	$1,515	$0	$2,222	**$20,285**	$37
13	IMPROVEMENTS TO SITE	$2,827	$1,625	$5,741	$0	$0	**$10,194**	$1,001	$0	$2,239	**$13,434**	$24
14	BUILDINGS & STRUCTURES	$0	$21,560	$20,672	$0	$0	**$42,232**	$3,805	$0	$6,906	**$52,943**	$96
	TOTAL COST	**$423,786**	**$42,490**	**$241,370**	**$0**	**$0**	**$707,646**	**$66,300**	**$0**	**$92,445**	**$866,391**	**$1,575**

Exhibit 4-34 Case 11 Total Plant Cost Details

	Client:	USDOE/NETL								Report Date:	09-May-07		
	Project:	Bituminous Baseline Study											
		TOTAL PLANT COST SUMMARY											
	Case:	Case 11 - Supercritical PC w/o CO2											
	Plant Size:	550.2 MW,net		Estimate Type:		Conceptual				Cost Base (Dec)	2006	($x1000)	

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	$3,183	$0	$1,469	$0	$0	$4,652	$415	$0	$760	$5,827	$11
1.2	Coal Stackout & Reclaim	$4,113	$0	$942	$0	$0	$5,055	$442	$0	$825	$6,322	$11
1.3	Coal Conveyors	$3,824	$0	$932	$0	$0	$4,756	$417	$0	$776	$5,949	$11
1.4	Other Coal Handling	$1,001	$0	$216	$0	$0	$1,216	$106	$0	$198	$1,521	$3
1.5	Sorbent Receive & Unload	$127	$0	$39	$0	$0	$166	$15	$0	$27	$208	$0
1.6	Sorbent Stackout & Reclaim	$2,056	$0	$381	$0	$0	$2,437	$212	$0	$397	$3,047	$6
1.7	Sorbent Conveyors	$734	$158	$182	$0	$0	$1,073	$93	$0	$175	$1,341	$2
1.8	Other Sorbent Handling	$443	$103	$235	$0	$0	$781	$69	$0	$128	$978	$2
1.9	Coal & Sorbent Hnd.Foundations	$0	$3,922	$4,982	$0	$0	$8,904	$832	$0	$1,460	$11,197	$20
	SUBTOTAL 1.	**$15,481**	**$4,183**	**$9,376**	**$0**	**$0**	**$29,040**	**$2,602**	**$0**	**$4,746**	**$36,389**	**$66**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	$1,823	$0	$359	$0	$0	$2,182	$190	$0	$356	$2,728	$5
2.2	Coal Conveyor to Storage	$4,668	$0	$1,030	$0	$0	$5,698	$498	$0	$929	$7,125	$13
2.3	Coal Injection System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.4	Misc.Coal Prep & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.5	Sorbent Prep Equipment	$3,493	$150	$733	$0	$0	$4,376	$381	$0	$714	$5,470	$10
2.6	Sorbent Storage & Feed	$421	$0	$163	$0	$0	$584	$52	$0	$95	$731	$1
2.7	Sorbent Injection System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.8	Booster Air Supply System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.9	Coal & Sorbent Feed Foundation	$0	$453	$353	$0	$0	$807	$74	$0	$132	$1,013	$2
	SUBTOTAL 2.	**$10,405**	**$603**	**$2,638**	**$0**	**$0**	**$13,646**	**$1,196**	**$0**	**$2,226**	**$17,068**	**$31**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	$17,490	$0	$5,725	$0	$0	$23,214	$2,033	$0	$3,787	$29,034	$53
3.2	Water Makeup & Pretreating	$4,278	$0	$1,376	$0	$0	$5,654	$530	$0	$1,237	$7,420	$13
3.3	Other Feedwater Subsystems	$5,404	$0	$2,293	$0	$0	$7,697	$686	$0	$1,257	$9,641	$18
3.4	Service Water Systems	$844	$0	$456	$0	$0	$1,300	$121	$0	$284	$1,705	$3
3.5	Other Boiler Plant Systems	$6,403	$0	$6,264	$0	$0	$12,667	$1,188	$0	$2,078	$15,933	$29
3.6	FO Supply Sys & Nat Gas	$247	$0	$304	$0	$0	$551	$51	$0	$90	$692	$1
3.7	Waste Treatment Equipment	$2,883	$0	$1,652	$0	$0	$4,535	$439	$0	$995	$5,969	$11
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	$2,558	$0	$788	$0	$0	$3,346	$321	$0	$733	$4,400	$8
	SUBTOTAL 3.	**$40,107**	**$0**	**$18,856**	**$0**	**$0**	**$58,963**	**$5,369**	**$0**	**$10,462**	**$74,795**	**$136**
4	PC BOILER											
4.1	PC Boiler & Accessories	$148,766	$0	$83,888	$0	$0	$232,654	$22,535	$0	$25,519	$280,708	$510
4.2	SCR (w/4.1)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.3	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.4	Boiler BoP (w/ ID Fans)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.5	Primary Air System	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.6	Secondary Air System	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.8	Major Component Rigging	$0	w/4.1	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.9	Boiler Foundations	$0	w/14.1	w/14.1	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 4.	**$148,766**	**$0**	**$83,888**	**$0**	**$0**	**$232,654**	**$22,535**	**$0**	**$25,519**	**$280,708**	**$510**

Exhibit 4-34 Case 11 Total Plant Cost Details (Continued)

	Client:	USDOE/NETL							Report Date:	09-May-07		
	Project:	Bituminous Baseline Study										
		TOTAL PLANT COST SUMMARY										
	Case:	Case 11 - Supercritical PC w/o CO2										
	Plant Size:	550.2 MW,net		Estimate Type:		Conceptual			Cost Base (Dec)	2006	($x1000)	
Acct		**Equipment**	**Material**	**Labor**		**Sales**	**Bare Erected**	**Eng'g CM**	**Contingencies**		**TOTAL PLANT COST**	
No.	**Item/Description**	**Cost**	**Cost**	**Direct**	**Indirect**	**Tax**	**Cost $**	**H.O.& Fee**	**Process**	**Project**	**$**	**$/kW**
5	FLUE GAS CLEANUP											
5.1	Absorber Vessels & Accessories	$54,227	$0	$11,683	$0	$0	$65,910	$6,238	$0	$7,215	$79,363	$144
5.2	Other FGD	$2,830	$0	$3,209	$0	$0	$6,039	$582	$0	$662	$7,283	$13
5.3	Bag House & Accessories	$15,654	$0	$9,942	$0	$0	$25,596	$2,448	$0	$2,804	$30,849	$56
5.4	Other Particulate Removal Materials	$1,059	$0	$1,134	$0	$0	$2,194	$211	$0	$241	$2,646	$5
5.5	Gypsum Dewatering System	$4,304	$0	$732	$0	$0	$5,036	$476	$0	$551	$6,063	$11
5.6	Mercury Removal System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5.9	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 5.	**$78,075**	**$0**	**$26,700**	**$0**	**$0**	**$104,775**	**$9,955**	**$0**	**$11,473**	**$126,203**	**$229**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
6.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.3	Compressed Air Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.9	Combustion Turbine Foundations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 6.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
7.2	HRSG Accessories	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$8,242	$0	$5,379	$0	$0	$13,621	$1,190	$0	$2,222	$17,033	$31
7.4	Stack	$8,411	$0	$4,925	$0	$0	$13,336	$1,274	$0	$1,461	$16,071	$29
7.9	Duct & Stack Foundations	$0	$959	$1,097	$0	$0	$2,056	$192	$0	$449	$2,697	$5
	SUBTOTAL 7.	**$16,653**	**$959**	**$11,402**	**$0**	**$0**	**$29,013**	**$2,656**	**$0**	**$4,132**	**$35,801**	**$65**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$48,728	$0	$6,532	$0	$0	$55,260	$5,291	$0	$6,055	$66,606	$121
8.2	Turbine Plant Auxiliaries	$334	$0	$716	$0	$0	$1,050	$102	$0	$115	$1,268	$2
8.3	Condenser & Auxiliaries	$6,405	$0	$2,204	$0	$0	$8,610	$818	$0	$943	$10,370	$19
8.4	Steam Piping	$16,354	$0	$8,078	$0	$0	$24,433	$2,039	$0	$3,971	$30,443	$55
8.9	TG Foundations	$0	$1,042	$1,658	$0	$0	$2,699	$254	$0	$591	$3,544	$6
	SUBTOTAL 8.	**$71,822**	**$1,042**	**$19,188**	**$0**	**$0**	**$92,052**	**$8,504**	**$0**	**$11,675**	**$112,231**	**$204**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$8,669	$0	$2,702	$0	$0	$11,371	$1,079	$0	$1,245	$13,695	$25
9.2	Circulating Water Pumps	$1,765	$0	$111	$0	$0	$1,876	$160	$0	$204	$2,239	$4
9.3	Circ.Water System Auxiliaries	$515	$0	$69	$0	$0	$583	$55	$0	$64	$702	$1
9.4	Circ.Water Piping	$0	$4,150	$3,958	$0	$0	$8,108	$747	$0	$1,328	$10,183	$19
9.5	Make-up Water System	$457	$0	$605	$0	$0	$1,062	$101	$0	$174	$1,337	$2
9.6	Component Cooling Water Sys	$411	$0	$324	$0	$0	$735	$69	$0	$121	$924	$2
9.9	Circ.Water System Foundations& Structures	$0	$2,403	$3,844	$0	$0	$6,247	$588	$0	$1,367	$8,202	$15
	SUBTOTAL 9.	**$11,816**	**$6,553**	**$11,613**	**$0**	**$0**	**$29,981**	**$2,799**	**$0**	**$4,503**	**$37,283**	**$68**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Ash Coolers	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.2	Cyclone Ash Letdown	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.3	HGCU Ash Letdown	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.4	High Temperature Ash Piping	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.5	Other Ash Recovery Equipment	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$563	$0	$1,735	$0	$0	$2,298	$224	$0	$252	$2,774	$5
10.7	Ash Transport & Feed Equipment	$3,669	$0	$3,735	$0	$0	$7,403	$700	$0	$810	$8,914	$16
10.8	Misc. Ash Handling Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.9	Ash/Spent Sorbent Foundation	$0	$133	$158	$0	$0	$291	$27	$0	$64	$381	$1
	SUBTOTAL 10.	**$4,232**	**$133**	**$5,628**	**$0**	**$0**	**$9,992**	**$951**	**$0**	**$1,126**	**$12,069**	**$22**

Exhibit 4-34 Case 11 Total Plant Cost Details (Continued)

Client: USDOE/NETL **Report Date:** 09-May-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 11 - Supercritical PC w/o CO2
Plant Size: 550.2 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$1,524	$0	$249	$0	$0	$1,773	$164	$0	$145	$2,083	$4
11.2	Station Service Equipment	$2,578	$0	$882	$0	$0	$3,460	$331	$0	$284	$4,075	$7
11.3	Switchgear & Motor Control	$3,063	$0	$525	$0	$0	$3,588	$332	$0	$392	$4,312	$8
11.4	Conduit & Cable Tray	$0	$1,967	$6,693	$0	$0	$8,660	$829	$0	$1,423	$10,913	$20
11.5	Wire & Cable	$0	$3,568	$7,051	$0	$0	$10,619	$895	$0	$1,727	$13,241	$24
11.6	Protective Equipment	$243	$0	$861	$0	$0	$1,104	$108	$0	$121	$1,333	$2
11.7	Standby Equipment	$1,176	$0	$28	$0	$0	$1,204	$114	$0	$132	$1,450	$3
11.8	Main Power Transformers	$6,950	$0	$165	$0	$0	$7,116	$541	$0	$766	$8,422	$15
11.9	Electrical Foundations	$0	$297	$735	$0	$0	$1,032	$98	$0	$226	$1,356	$2
	SUBTOTAL 11.	**$15,533**	**$5,832**	**$17,190**	**$0**	**$0**	**$38,556**	**$3,411**	**$0**	**$5,217**	**$47,183**	**$86**
12	INSTRUMENTATION & CONTROL											
12.1	PC Control Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
12.3	Steam Turbine Control	w/8.1	$0	w/8.1	$0	$0	$0	$0	$0	$0	$0	$0
12.4	Other Major Component Control	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
12.5	Signal Processing Equipment	W/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.6	Control Boards,Panels & Racks	$413	$0	$258	$0	$0	$671	$65	$0	$110	$846	$2
12.7	Distributed Control System Equipment	$4,172	$0	$760	$0	$0	$4,932	$470	$0	$540	$5,942	$11
12.8	Instrument Wiring & Tubing	$2,305	$0	$4,674	$0	$0	$6,979	$594	$0	$1,136	$8,710	$16
12.9	Other I & C Equipment	$1,179	$0	$2,787	$0	$0	$3,966	$386	$0	$435	$4,788	$9
	SUBTOTAL 12.	**$8,069**	**$0**	**$8,480**	**$0**	**$0**	**$16,549**	**$1,515**	**$0**	**$2,222**	**$20,285**	**$37**
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation	$0	$48	$958	$0	$0	$1,005	$99	$0	$221	$1,325	$2
13.2	Site Improvements	$0	$1,578	$1,974	$0	$0	$3,552	$349	$0	$780	$4,681	$9
13.3	Site Facilities	$2,827	$0	$2,809	$0	$0	$5,637	$553	$0	$1,238	$7,428	$14
	SUBTOTAL 13.	**$2,827**	**$1,625**	**$5,741**	**$0**	**$0**	**$10,194**	**$1,001**	**$0**	**$2,239**	**$13,434**	**$24**
14	BUILDINGS & STRUCTURES											
14.1	Boiler Building	$0	$7,843	$6,990	$0	$0	$14,833	$1,332	$0	$2,425	$18,590	$34
14.2	Turbine Building	$0	$11,220	$10,597	$0	$0	$21,817	$1,964	$0	$3,567	$27,348	$50
14.3	Administration Building	$0	$554	$594	$0	$0	$1,147	$104	$0	$188	$1,439	$3
14.4	Circulation Water Pumphouse	$0	$159	$128	$0	$0	$286	$26	$0	$47	$359	$1
14.5	Water Treatment Buildings	$0	$565	$471	$0	$0	$1,036	$93	$0	$169	$1,299	$2
14.6	Machine Shop	$0	$370	$252	$0	$0	$623	$55	$0	$102	$780	$1
14.7	Warehouse	$0	$251	$255	$0	$0	$506	$46	$0	$83	$635	$1
14.8	Other Buildings & Structures	$0	$205	$177	$0	$0	$382	$34	$0	$62	$479	$1
14.9	Waste Treating Building & Str.	$0	$393	$1,208	$0	$0	$1,601	$151	$0	$263	$2,015	$4
	SUBTOTAL 14.	**$0**	**$21,560**	**$20,672**	**$0**	**$0**	**$42,232**	**$3,805**	**$0**	**$6,906**	**$52,943**	**$96**
	TOTAL COST	**$423,786**	**$42,490**	**$241,370**	**$0**	**$0**	**$707,646**	**$66,300**	**$0**	**$92,445**	**$866,391**	**$1,575**

Exhibit 4-35 Case 11 Initial and Annual Operating and Maintenance Costs

INITIAL & ANNUAL O&M EXPENSES						Cost Base (Dec)	2006
Case 11 - Supercritical PC w/o CO2						Heat Rate-net(Btu/kWh):	8,721
						MWe-net:	550
						Capacity Factor: (%):	85
OPERATING & MAINTENANCE LABOR							
Operating Labor							
Operating Labor Rate(base):	33.00	$/hour					
Operating Labor Burden:	30.00	% of base					
Labor O-H Charge Rate:	25.00	% of labor					
			Total				
Skilled Operator	2.0		2.0				
Operator	9.0		9.0				
Foreman	1.0		1.0				
Lab Tech's, etc.	2.0		2.0				
TOTAL-O.J.'s	14.0		14.0				
						Annual Cost	Annual Unit Cost
						$	$/kW-net
Annual Operating Labor Cost						$5,261,256	$9.563
Maintenance Labor Cost						$5,818,574	$10.576
Administrative & Support Labor						$2,769,958	$5.035
TOTAL FIXED OPERATING COSTS						**$13,849,788**	**$25.175**
VARIABLE OPERATING COSTS							
							$/kWh-net
Maintenance Material Cost						**$8,727,862**	**$0.00213**
Consumables	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost			
Water(/1000 gallons)	0	3,918	1.03	**$0**		**$1,251,873**	**$0.00031**
Chemicals							
MU & WT Chem.(lb)	132,743	18,963	0.16	$21,876		$969,578	$0.00024
Limestone (ton)	3,429	490	20.60	$70,633		$3,130,564	$0.00076
Carbon (Mercury Removal) (lb)	0	0	1.00	$0		$0	$0.00000
MEA Solvent (ton)	0	0	2,142.40	$0		$0	$0.00000
NaOH (tons)	0	0	412.96	$0		$0	$0.00000
H2SO4 (tons)	0	0	132.15	$0		$0	$0.00000
Corrosion Inhibitor	0	0	0.00	$0		$0	$0.00000
Activated Carbon(lb)	0	0	1.00	$0		$0	$0.00000
Ammonia (28% NH3) ton	517	74	123.60	$63,883		$2,831,382	$0.00069
Subtotal Chemicals				**$156,392**		**$6,931,524**	**$0.00169**
Other							
Supplemental Fuel(MBtu)	0	0	0.00	$0		$0	$0.00000
SCR Catalyst(m3)	w/equip.	0.44	5,500.00	$0		$747,563	$0.00018
Emission Penalties	0	0	0.00	$0		$0	$0.00000
Subtotal Other				**$0**		**$747,563**	**$0.00018**
Waste Disposal							
Flyash (ton)	0	96	15.45	$0		$458,782	$0.00011
Bottom Ash(ton)	0	383	15.45	$0		$1,835,187	$0.00045
Subtotal-Waste Disposal				**$0**		**$2,293,969**	**$0.00056**
By-products & Emissions							
Gypsum (tons)	0	739	0.00	$0		$0	$0.00000
Subtotal By-Products				**$0**		**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$156,392**		**$19,952,791**	**$0.00487**
Fuel(ton)	148,057	4,935	42.11	**$6,234,675**		**$64,476,927**	**$0.01574**

4.3.7 CASE 12 – SUPERCRITICAL PC WITH CO_2 CAPTURE

The plant configuration for Case 12, supercritical PC, is the same as Case 11 with the exception that the Econamine FG Plus CDR technology was added for CO_2 capture. The nominal net output is maintained at 550 MW by increasing the boiler size and turbine/generator size to account for the greater auxiliary load imposed by the CDR facility. Unlike the IGCC cases where gross output was fixed by the available size of the combustion turbines, the PC cases utilize boilers and steam turbines that can be procured at nearly any desired output making it possible to maintain a constant net output.

The process description for Case 12 is essentially the same as Case 11 with one notable exception, the addition of CO_2 capture. A BFD and stream tables for Case 12 are shown in Exhibit 4-36 and Exhibit 4-37, respectively. Since the CDR facility process description was provided in Section 4.1.7, it is not repeated here.

4.3.8 CASE 12 PERFORMANCE RESULTS

The Case 12 modeling assumptions were presented previously in Section 4.3.2.

The plant produces a net output of 546 MW at a net plant efficiency of 27.2 percent (HHV basis). Overall plant performance is summarized in Exhibit 4-38 which includes auxiliary power requirements. The CDR facility, including CO_2 compression, accounts for over 58 percent of the auxiliary plant load. The circulating water system (circulating water pumps and cooling tower fan) accounts for over 15 percent of the auxiliary load, largely due to the high cooling water demand of the CDR facility.

Exhibit 4-36 Case 12 Process Flow Diagram, Supercritical Unit with CO_2 Capture

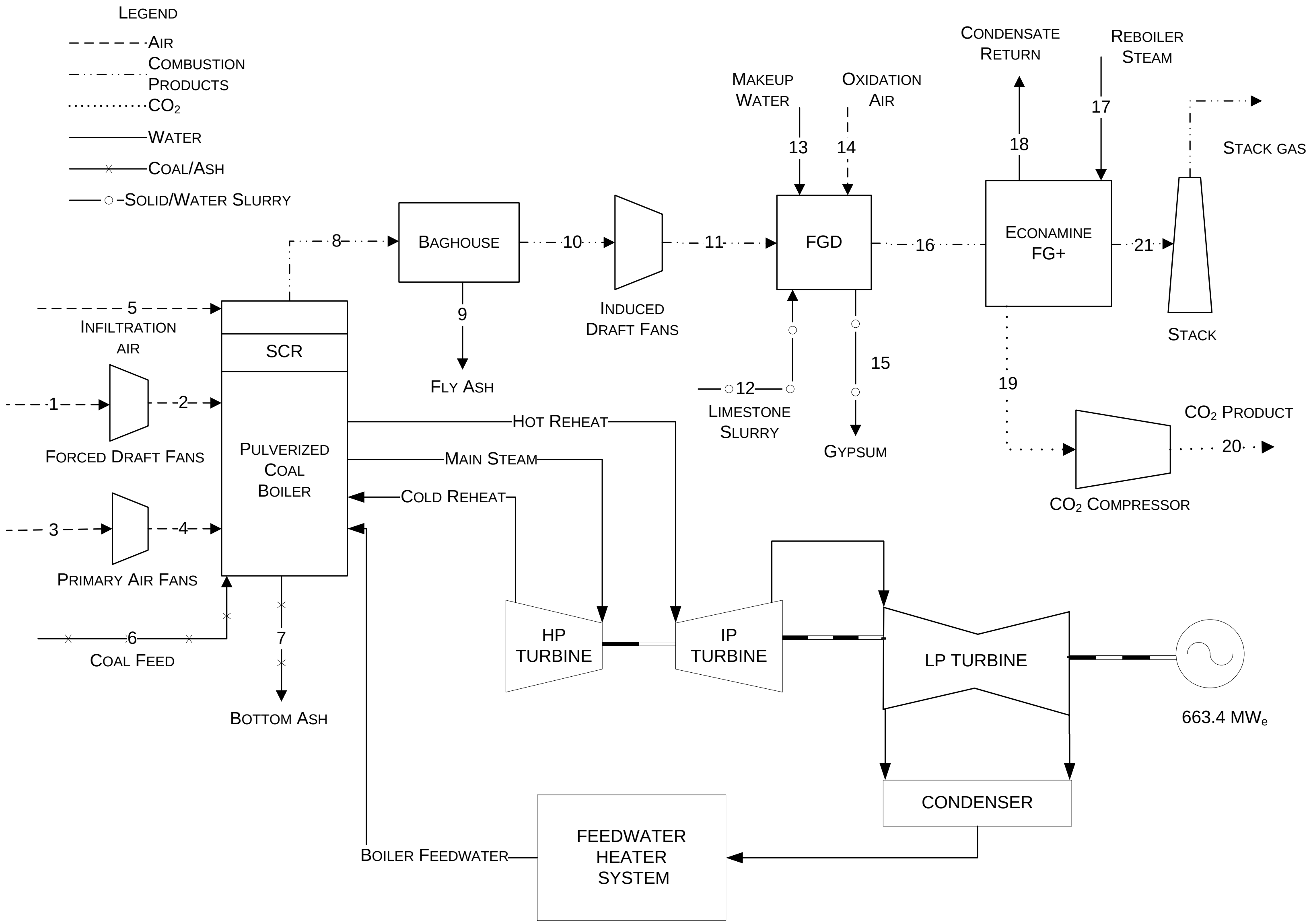

Exhibit 4-37 Case 12 Stream Table, Supercritical Unit with CO_2 Capture

	1	2	3	4	5	6	7	8	9	10	11
V-L Mole Fractions											
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0087	0.0000	0.0087	0.0087
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.1450	0.0000	0.1450	0.1450
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	0.0870	0.0000	0.0870	0.0870
N_2	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.7324	0.0000	0.7324	0.7324
O_2	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0247	0.0000	0.0247	0.0247
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021	0.0000	0.0021	0.0021
Total	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	0.0000	1.0000	1.0000
V-L Flow (lb_{mol}/hr)	153,570	153,570	47,175	47,175	2,650	0	0	215,146	0	215,146	215,146
V-L Flow (lb/hr)	4,431,560	4,431,560	1,361,330	1,361,330	76,466	0	0	6,399,090	0	6,399,090	6,399,090
Solids Flowrate	0	0	0	0	0	586,627	11,377	45,507	45,507	0	0
Temperature (°F)	59	66	59	78	59	59	350	350	350	350	370
Pressure (psia)	14.70	15.25	14.70	16.14	14.70	14.70	14.40	14.40	14.20	14.20	15.26
Enthalpy (BTU/lb)[A]	13.1	14.9	13.1	17.7	13.1	11,676	51.4	135.6	51.4	136.2	141.5
Density (lb/ft^3)	0.08	0.08	0.08	0.08	0.08	---	---	0.05	---	0.05	0.05
Avg. Molecular Weight	28.86	28.86	28.86	28.86	28.86	---	---	29.74	---	29.74	29.74

	12	13	14	15	16	17	18	19	20	21
V-L Mole Fraction										
Ar	0.0000	0.0000	0.0092	0.0000	0.0080	0.0000	0.0000	0.0000	0.0000	0.0109
CO_2	0.0000	0.0000	0.0003	0.0015	0.1326	0.0000	0.0000	0.9862	1.0000	0.0180
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	1.0000	1.0000	0.0099	0.9977	0.1668	1.0000	1.0000	0.0138	0.0000	0.0281
N_2	0.0000	0.0000	0.7732	0.0008	0.6690	0.0000	0.0000	0.0000	0.0000	0.9109
O_2	0.0000	0.0000	0.2074	0.0000	0.0235	0.0000	0.0000	0.0000	0.0000	0.0320
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	7,537	34,486	2,535	20,128	238,453	100,792	100,792	28,856	28,458	175,090
V-L Flowrate (lb/hr)	135,788	621,279	73,155	363,564	6,833,360	1,815,800	1,815,800	1,259,600	1,252,440	4,951,450
Solids Flowrate (lb/hr)	58,054	0	0	90,446	0	0	0	0	0	0
Temperature (°F)	59	60	59	135	135	692	348	69	124	74
Pressure (psia)	14.70	14.70	14.70	15.20	15.20	130.86	130.86	23.52	2215.00	14.70
Enthalpy (BTU/lb)[A]	---	33.3	13.1	88.0	139.4	1373.8	319.5	11.4	-70.8	29.6
Density (lb/ft^3)	62.62	62.59	0.08	39.94	0.07	0.19	55.67	0.18	40.76	0.07
Molecular Weight	18.02	18.02	28.86	18.06	28.66	18.02	18.02	43.65	44.01	28.28

A - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 4-38 Case 12 Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
TOTAL (STEAM TURBINE) POWER, kWe	**663,445**
AUXILIARY LOAD SUMMARY, kWe (Note 1)	
Coal Handling and Conveying	490
Limestone Handling & Reagent Preparation	1,270
Pulverizers	3,990
Ash Handling	760
Primary Air Fans	1,870
Forced Draft Fans	2,380
Induced Draft Fans	10,120
SCR	70
Baghouse	100
FGD Pumps and Agitators	4,250
Econamine FG Plus Auxiliaries	21,320
CO_2 Compression	46,900
Miscellaneous Balance of Plant (Note 2)	2,000
Steam Turbine Auxiliaries	400
Condensate Pumps	630
Circulating Water Pumps	12,260
Cooling Tower Fans	6,340
Transformer Loss	2,300
TOTAL AUXILIARIES, kWe	**117,450**
NET POWER, kWe	**545,995**
Net Plant Efficiency (HHV)	27.2%
Net Plant Heat Rate (Btu/kWh)	12,534
CONDENSER COOLING DUTY, 10^6 kJ/h (10^6 Btu/h)	1,884 (1,787)
CONSUMABLES	
As-Received Coal Feed, kg/h (lb/h)	266,090 (586,627)
Limestone Sorbent Feed, kg/h (lb/h)	26,333 (58,054)
Thermal Input, kWt	2,005,660
Makeup Water, m^3/min (gpm)	46.0 (12,159)

Notes: 1. Boiler feed pumps are steam turbine driven
2. Includes plant control systems, lighting, HVAC and miscellanous low voltage loads

Environmental Performance

The environmental targets for emissions of Hg, NOx, SO_2, and particulate matter were presented in Section 2.4. A summary of the plant air emissions for Case 12 is presented in Exhibit 4-39.

Exhibit 4-39 Case 12 Air Emissions

	kg/GJ ($lb/10^6$ Btu)	Tonne/year (ton/year) 85% capacity factor	kg/MWh (lb/MWh)
SO_2	Negligible	Negligible	Negligible
NO_X	0.030 (0.070)	1,618 (1,784)	0.328 (0.722)
Particulates	0.006 (0.013)	300 (331)	0.061 (0.134)
Hg	0.49×10^{-6} (1.14×10^{-6})	0.026 (0.029)	5.3×10^{-6} (11.8×10^{-6})
CO_2	8.7 (20)	468,000 (516,000)	95 (209)
CO_2[1]			115 (254)

[1] CO_2 emissions based on net power instead of gross power

SO_2 emissions are controlled using a wet limestone forced oxidation scrubber that achieves a removal efficiency of 98 percent. The byproduct calcium sulfate is dewatered and stored on site. The wallboard grade material can potentially be marketed and sold, but since it is highly dependent on local market conditions, no byproduct credit was taken. The SO_2 emissions are further reduced to 10 ppmv using a NaOH based polishing scrubber in the CDR facility. The remaining low concentration of SO_2 is essentially completely removed in the CDR absorber vessel resulting in negligible SO_2 emissions.

NOx emissions are controlled to about 0.5 $lb/10^6$ Btu through the use of LNBs and OFA. An SCR unit then further reduces the NOx concentration by 86 percent to 0.07 $lb/10^6$ Btu.

Particulate emissions are controlled using a pulse jet fabric filter which operates at an efficiency of 99.8 percent.

Co-benefit capture results in a 90 percent reduction of mercury emissions. Ninety percent of the CO_2 in the flue gas is removed in CDR facility.

Exhibit 4-40 shows the overall water balance for the plant. Raw water is obtained from groundwater (50 percent) and from municipal sources (50 percent). The water usage represents only the contribution of raw water makeup. In some cases the water demand is greater than raw water makeup because of internal water recycle streams. For example, the boiler feedwater blowdown stream and condensate recovered from cooling the flue gas prior to the CO_2 absorber are re-used as makeup to the cooling tower, thus reducing the raw water requirement by that amount.

Exhibit 4-40 Case 12 Water Balance

Water Use	Water Demand, m^3/min (gpm)	Internal Recycle, m^3/min (gpm)	Raw Water Makeup, m^3/min (gpm)
FGD Makeup	2.9 (779)	0	2.9 (779)
BFW Makeup	0.4 (105)	0	0.4 (105)
Cooling Tower Makeup	41.2 (10,885)	5.0 (1,324)	36.2 (9,561)
Total	**44.5 (11,769)**	**5.0 (1,324)**	**39.5 (10,444)**

Heat and Mass Balance Diagrams

A heat and mass balance diagram is shown for the Case 12 PC boiler, the FGD unit, CDR system and steam cycle in Exhibit 4-41.

An overall plant energy balance is provided in tabular form in Exhibit 4-42. The power out is the steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 4-38) is calculated by multiplying the power out by a generator efficiency of 98.5 percent. The Econamine process heat out stream represents heat rejected to cooling water and ultimately to ambient via the cooling tower. The same is true of the condenser heat out stream. The CO_2 compressor intercooler load is included in the Econamine process heat out stream.

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Exhibit 4-41 Case 12 Heat and Mass Balance, Supercritical PC Boiler with CO_2 Capture

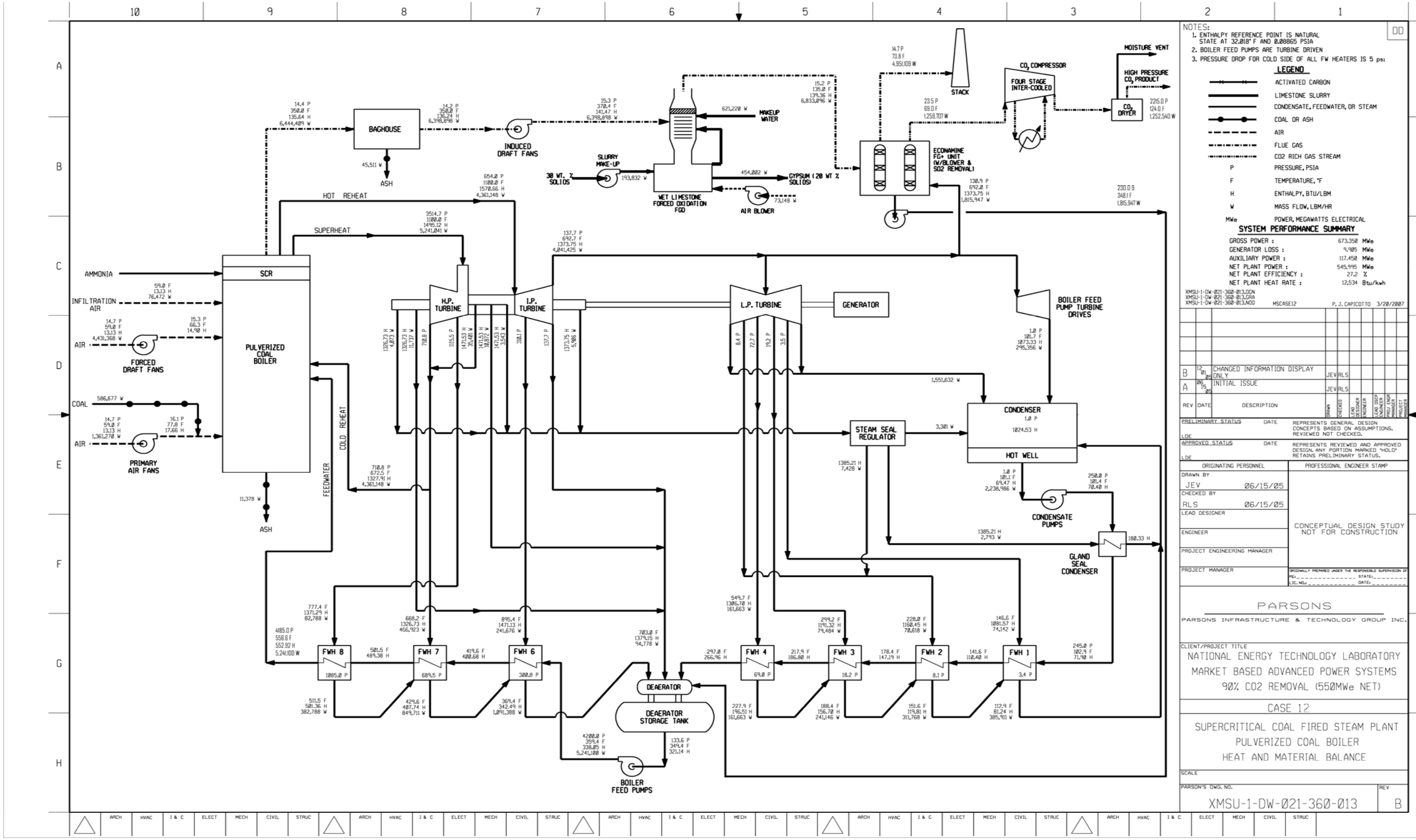

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Exhibit 4-42 Case 12 Overall Energy Balance (0°C [32°F] Reference)

	HHV	Sensible + Latent	Power	Total
Heat In (MMBtu/hr)				
Coal	6,843.6	5.7		6,849.3
Ambient Air		76.1		76.1
Infiltration Air		1.0		1.0
Limestone		87.1		87.1
FGD Oxidant		1.0		1.0
Raw Water Makeup		136.4		136.4
Auxiliary Power			424.2	424.2
Totals	**6,843.6**	**307.3**	**424.2**	**7,575.0**
Heat Out (MMBtu/hr)				
Bottom Ash		0.6		0.6
Fly Ash		2.3		2.3
Flue Gas Exhaust		229.1		229.1
CO_2 Product		(88.7)		(88.7)
Condenser		1,787.0		1,787.0
Econamime Process		3154.6		3154.6
Cooling Tower Blowdown		63.3		63.3
Gypsum Slurry		2.8		2.8
Process Losses (1)		124.5		124.5
Power			2,299.5	2,299.5
Totals	**0.0**	**5,275.6**	**2,299.5**	**7,575.0**

(1) Process Losses are calculated by difference and reflect various boiler, turbine, and other heat and work losses. Aspen flowsheet balance is within 0.5 percent.

4.3.9 CASE 12 – MAJOR EQUIPMENT LIST

Major equipment items for the supercritical PC plant with CO_2 capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 4.3.10. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

ACCOUNT 1 FUEL AND SORBENT HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	181 tonne (200 ton)	2	0
2	Feeder	Belt	572 tonne/h (630 tph)	2	0
3	Conveyor No. 1	Belt	1,134 tonne/h (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,134 tonne/h (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,134 tonne/h (1,250 tph)	1	0
8	Reclaim Hopper	N/A	54 tonne (60 ton)	2	1
9	Feeder	Vibratory	218 tonne/h (240 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	435 tonne/h (480 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	218 tonne (240 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3" x 0 - 1-1/4" x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	435 tonne/h (480 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	435 tonne/h (480 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	998 tonne (1,100 ton)	3	0
19	Limestone Truck Unloading Hopper	N/A	36 tonne (40 ton)	1	0
20	Limestone Feeder	Belt	109 tonne/h (120 tph)	1	0
21	Limestone Conveyor No. L1	Belt	109 tonne/h (120 tph)	1	0
22	Limestone Reclaim Hopper	N/A	18 tonne (20 ton)	1	0
23	Limestone Reclaim Feeder	Belt	91 tonne/h (100 tph)	1	0
24	Limestone Conveyor No. L2	Belt	91 tonne/h (100 tph)	1	0
25	Limestone Day Bin	w/ actuator	345 tonne (380 ton)	2	0

ACCOUNT 2 COAL AND SORBENT PREPARATION AND FEED

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	45 tonne/h (50 tph)	6	0
2	Coal Pulverizer	Ball type or equivalent	45 tonne/h (50 tph)	6	0
3	Limestone Weigh Feeder	Gravimetric	29 tonne/h (32 tph)	1	1
4	Limestone Ball Mill	Rotary	29 tonne/h (32 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	109,778 liters (29,000 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	445 lpm @ 12m H2O (490 gpm @ 40 ft H2O)	1	1
7	Hydroclone Classifier	4 active cyclones in a 5 cyclone bank	109 lpm (120 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1
9	Limestone Slurry Storage Tank with Agitator	Field erected	624,598 liters (165,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	308 lpm @ 9m H2O (340 gpm @ 30 ft H2O)	1	1

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	1,570,958 liters (415,000 gal)	2	0
2	Condensate Pumps	Vertical canned	18,927 lpm @ 213 m H2O (5,000 gpm @ 700 ft H2O)	1	1
3	Deaerator and Storage Tank	Horizontal spray type	2,614,963 kg/h (5,765,000 lb/h) 5 min. tank	1	0
4	Boiler Feed Pump and Steam Turbine Drive	Barrel type, multi-stage, centrifugal	43,911 lpm @ 3,475 m H2O (11,600 gpm @ 11,400 ft H2O)	1	1
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	13,249 lpm @ 3,475 m H2O (3,500 gpm @ 11,400 ft H2O)	1	0
6	LP Feedwater Heater 1A/1B	Horizontal U-tube	557,919 kg/h (1,230,000 lb/h)	2	0
7	LP Feedwater Heater 2A/2B	Horizontal U-tube	557,919 kg/h (1,230,000 lb/h)	2	0
8	LP Feedwater Heater 3A/3B	Horizontal U-tube	557,919 kg/h (1,230,000 lb/h)	2	0
9	LP Feedwater Heater 4A/4B	Horizontal U-tube	557,919 kg/h (1,230,000 lb/h)	2	0
10	HP Feedwater Heater 6	Horizontal U-tube	2,612,695 kg/h (5,760,000 lb/h)	1	0
11	HP Feedwater Heater 7	Horizontal U-tube	2,612,695 kg/h (5,760,000 lb/h)	1	0
12	HP Feedwater heater 8	Horizontal U-tube	2,612,695 kg/h (5,760,000 lb/h)	1	0
13	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/h, 2.8 MPa, 343°C (40,000 lb/h, 400 psig, 650°F)	1	0
14	Fuel Oil System	No. 2 fuel oil for light off	1,135,632 liter (300,000 gal)	1	0
15	Service Air Compressors	Flooded Screw	28 m3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
16	Instrument Air Dryers	Duplex, regenerative	28 m3/min (1,000 scfm)	2	1
17	Closed Cycle Cooling Heat Exchangers	Shell and tube	53 MMkJ/h (50 MMBtu/h) each	2	0
18	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,820 lpm @ 30 m H2O (5,500 gpm @ 100 ft H2O)	2	1
19	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H2O (1,000 gpm @ 290 ft H2O)	1	1
20	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H2O (700 gpm @ 210 ft H2O)	1	1
21	Raw Water Pumps	Stainless steel, single suction	25,514 lpm @ 43 m H2O (6,740 gpm @ 140 ft H2O)	2	1
22	Filtered Water Pumps	Stainless steel, single suction	2,120 lpm @ 49 m H2O (560 gpm @ 160 ft H2O)	2	1
23	Filtered Water Tank	Vertical, cylindrical	2,040,353 liter (539,000 gal)	1	0
24	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	1,022 lpm (270 gpm)	1	1
25	Liquid Waste Treatment System	--	10 years, 24-hour storm	1	0

ACCOUNT 4 BOILER AND ACCESSORIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Supercritical, drum, wall-fired, low NOx burners, overfire air	2,612,695 kg/h steam @ 24.1 MPa/593°C/593°C (5,760,000 lb/h steam @ 3,500 psig/1,100°F/1,100°F)	1	0
2	Primary Air Fan	Centrifugal	339,741 kg/h, 4,650 m3/min @ 123 cm WG (749,000 lb/h, 164,200 acfm @ 48 in. WG)	2	0
3	Forced Draft Fan	Centrifugal	1,105,406 kg/h, 15,135 m3/min @ 47 cm WG (2,437,000 lb/h, 534,500 acfm @ 19 in. WG)	2	0
4	Induced Draft Fan	Centrifugal	1,596,647 kg/h, 33,898 m3/min @ 90 cm WG (3,520,000 lb/h, 1,197,100 acfm @ 36 in. WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	3,193,294 kg/h (7,040,000 lb/h)	2	0
6	SCR Catalyst	--	--	3	0
7	Dilution Air Blower	Centrifugal	190 m3/min @ 108 cm WG (6,700 acfm @ 42 in. WG)	2	1
8	Ammonia Storage	Horizontal tank	208,199 liter (55,000 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	40 lpm @ 91 m H2O (11 gpm @ 300 ft H2O)	2	1

ACCOUNT 5 FLUE GAS CLEANUP

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Fabric Filter	Single stage, high-ratio with pulse-jet online cleaning system	1,596,647 kg/h (3,520,000 lb/h) 99.8% efficiency	2	0
2	Absorber Module	Counter-current open spray	52,160 m3/min (1,842,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	181,701 lpm @ 64 m H2O (48,000 gpm @ 210 ft H2O)	5	1
4	Bleed Pumps	Horizontal centrifugal	5,716 lpm (1,510 gpm) 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	250 m3/min @ 0.3 MPa (8,820 acfm @ 42 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	1,438 lpm (380 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	45 tonne/h (50 tph) 50 wt % slurry	2	1
9	Filtrate Water Return Pumps	Horizontal centrifugal	871 lpm @ 12 m H2O (230 gpm @ 40 ft H2O)	1	1
10	Filtrate Water Return Storage Tank	Vertical, lined	567,816 lpm (150,000 gal)	1	0
11	Process Makeup Water Pumps	Horizontal centrifugal	3,255 lpm @ 21 m H2O (860 gpm @ 70 ft H2O)	1	1

ACCOUNT 5C CARBON DIOXIDE RECOVERY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Econamine FG Plus	Amine-based CO2 capture technology	1,704,602 kg/h (3,758,000 lb/h) 20.4 wt % CO2 inlet concentration	2	0
2	CO2 Compressor	Integrally geared, multi-stage centrifugal	312,453 kg/h @ 15.3 MPa (688,840 lb/h @ 2,215 psia)	2	0

ACCOUNT 6 COMBUSTION TURBINE/ACCESSORIES

N/A

ACCOUNT 7 HRSG, DUCTING & STACK

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	152 m (500 ft) high x 5.5 m (18 ft) diameter	1	0

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	700 MW 24.1 MPa/593°C/593°C (3500 psig/ 1100°F/1100°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	780 MVA @ 0.9 p.f., 24 kV, 60 Hz	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	2,077 MMkJ/h (1,970 MMBtu/h), Inlet water temperature 16ºC (60ºF), Water temperature rise 11ºC (20ºF)	1	0

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	613,241 lpm @ 30.5 m (162,000 gpm @ 100 ft)	4	2
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT 5,914 MMkJ/h (5,610 MMBtu/h) heat load	1	0

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Economizer Hopper (part of boiler scope of supply)	--	--	4	0
2	Bottom Ash Hopper (part of boiler scope of supply)	--	--	2	0
3	Clinker Grinder	--	5.4 tonne/h (6 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	--	--	6	0
5	Hydroejectors	--	--	12	
6	Economizer /Pyrites Transfer Tank	--	--	1	0
7	Ash Sluice Pumps	Vertical, wet pit	227 lpm @ 17 m H2O (60 gpm @ 56 ft H2O)	1	1
8	Ash Seal Water Pumps	Vertical, wet pit	7,571 lpm @ 9 m H2O (2000 gpm @ 28 ft H2O)	1	1
9	Hydrobins	--	227 lpm (60 gpm)	1	1
10	Baghouse Hopper (part of baghouse scope of supply)	--	--	24	0
11	Air Heater Hopper (part of boiler scope of supply)	--	--	10	0
12	Air Blower	--	21 m3/min @ 0.2 MPa (730 scfm @ 24 psi)	1	1
13	Fly Ash Silo	Reinforced concrete	680 tonne (1,500 ton)	2	0
14	Slide Gate Valves	--	--	2	0
15	Unloader	--	--	1	0
16	Telescoping Unloading Chute	--	127 tonne/h (140 tph)	1	0

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 640 MVA, 3-ph, 60 Hz	1	0
2	Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 128 MVA, 3-ph, 60 Hz	1	1
3	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 19 MVA, 3-ph, 60 Hz	1	1
4	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
5	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
6	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
7	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

ACCOUNT 12 INSTRUMENTATION AND CONTROL

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

4.3.10 CASE 12 – COST ESTIMATING BASIS

The cost estimating methodology was described previously in Section 2.6. Exhibit 4-43 shows the total plant capital cost summary organized by cost account and Exhibit 4-44 shows a more detailed breakdown of the capital costs. Exhibit 4-45 shows the initial and annual O&M costs.

The estimated TPC of the subcritical PC boiler with CO_2 capture is $2,868/kW. Process contingency represents 3.5 percent of the TPC and project contingency represents 12.4 percent. The 20-year LCOE, including CO_2 TS&M costs of 3.9 mills/kWh, is 114.8 mills/kWh.

Exhibit 4-43 Case 12 Total Plant Cost Summary

	Client:	USDOE/NETL									**Report Date:**	09-May-07	
	Project:	Bituminous Baseline Study											
		TOTAL PLANT COST SUMMARY											
	Case:	Case 12 - Supercritical PC w/ CO2											
	Plant Size:	546.0 MW,net		**Estimate Type:**		Conceptual			**Cost Base (Dec)**	2006	($x1000)		

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	$19,316	$5,215	$11,691	$0	$0	**$36,222**	$3,246	$0	$5,920	**$45,389**	$83
2	COAL & SORBENT PREP & FEED	$13,126	$758	$3,326	$0	$0	**$17,210**	$1,508	$0	$2,808	**$21,527**	$39
3	FEEDWATER & MISC. BOP SYSTEMS	$54,477	$0	$25,648	$0	$0	**$80,126**	$7,317	$0	$14,428	**$101,870**	$187
4	PC BOILER											
4.1	PC Boiler & Accessories	$190,969	$0	$107,678	$0	$0	**$298,647**	$28,927	$0	$32,757	**$360,332**	$660
4.2	SCR (w/4.1)	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.3	Open	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.4-4.9	Boiler BoP (w/ ID Fans)	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
	SUBTOTAL 4	**$190,969**	**$0**	**$107,678**	**$0**	**$0**	**$298,647**	**$28,927**	**$0**	**$32,757**	**$360,332**	**$660**
5	FLUE GAS CLEANUP	$101,747	$0	$34,963	$0	$0	**$136,710**	$12,990	$0	$14,970	**$164,670**	$302
5B	CO_2 REMOVAL & COMPRESSION	$229,832	$0	$69,851	$0	$0	**$299,683**	$28,443	$52,879	$76,201	**$457,207**	$837
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	N/A	$0	N/A	$0	$0	**$0**	$0	$0	$0	**$0**	$0
6.2-6.9	Combustion Turbine Other	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
	SUBTOTAL 6	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	N/A	$0	N/A	$0	$0	**$0**	$0	$0	$0	**$0**	$0
7.2-7.9	HRSG Accessories, Ductwork and Stack	$17,889	$981	$12,221	$0	$0	**$31,091**	$2,840	$0	$4,457	**$38,388**	$70
	SUBTOTAL 7	**$17,889**	**$981**	**$12,221**	**$0**	**$0**	**$31,091**	**$2,840**	**$0**	**$4,457**	**$38,388**	**$70**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$53,763	$0	$7,192	$0	$0	**$60,956**	$5,836	$0	$6,679	**$73,471**	$135
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$26,923	$1,148	$14,942	$0	$0	**$43,013**	$3,724	$0	$6,698	**$53,436**	$98
	SUBTOTAL 8	**$80,687**	**$1,148**	**$22,134**	**$0**	**$0**	**$103,969**	**$9,561**	**$0**	**$13,377**	**$126,907**	**$232**
9	COOLING WATER SYSTEM	$21,479	$11,200	$19,881	$0	$0	**$52,559**	$4,900	$0	$7,796	**$65,255**	$120
10	ASH/SPENT SORBENT HANDLING SYS	$5,154	$162	$6,854	$0	$0	**$12,169**	$1,158	$0	$1,371	**$14,699**	$27
11	ACCESSORY ELECTRIC PLANT	$20,196	$10,240	$29,287	$0	$0	**$59,723**	$5,331	$0	$8,288	**$73,343**	$134
12	INSTRUMENTATION & CONTROL	$9,195	$0	$9,662	$0	$0	**$18,857**	$1,726	$943	$2,648	**$24,174**	$44
13	IMPROVEMENTS TO SITE	$3,162	$1,818	$6,421	$0	$0	**$11,402**	$1,120	$0	$2,504	**$15,026**	$28
14	BUILDINGS & STRUCTURES	$0	$23,760	$22,735	$0	$0	**$46,495**	$4,189	$0	$7,603	**$58,287**	$107
	TOTAL COST	**$767,230**	**$55,282**	**$382,352**	**$0**	**$0**	**$1,204,865**	**$113,256**	**$53,822**	**$195,130**	**$1,567,073**	**$2,870**

Exhibit 4-44 Case 12 Total Plant Cost Details

Client:	USDOE/NETL	**Report Date:**	09-May-07
Project:	Bituminous Baseline Study		
	TOTAL PLANT COST SUMMARY		
Case:	Case 12 - Supercritical PC w/ CO2		
Plant Size:	546.0 MW,net **Estimate Type:** Conceptual	**Cost Base (Dec)**	2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	$3,967	$0	$1,831	$0	$0	$5,797	$518	$0	$947	$7,262	$13
1.2	Coal Stackout & Reclaim	$5,126	$0	$1,174	$0	$0	$6,300	$551	$0	$1,028	$7,879	$14
1.3	Coal Conveyors	$4,766	$0	$1,161	$0	$0	$5,927	$520	$0	$967	$7,414	$14
1.4	Other Coal Handling	$1,247	$0	$269	$0	$0	$1,516	$132	$0	$247	$1,895	$3
1.5	Sorbent Receive & Unload	$160	$0	$49	$0	$0	$208	$18	$0	$34	$260	$0
1.6	Sorbent Stackout & Reclaim	$2,576	$0	$477	$0	$0	$3,053	$266	$0	$498	$3,817	$7
1.7	Sorbent Conveyors	$919	$198	$228	$0	$0	$1,345	$116	$0	$219	$1,680	$3
1.8	Other Sorbent Handling	$555	$129	$294	$0	$0	$979	$87	$0	$160	$1,225	$2
1.9	Coal & Sorbent Hnd.Foundations	$0	$4,888	$6,210	$0	$0	$11,097	$1,037	$0	$1,820	$13,955	$26
	SUBTOTAL 1.	**$19,316**	**$5,215**	**$11,691**	**$0**	**$0**	**$36,222**	**$3,246**	**$0**	**$5,920**	**$45,389**	**$83**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	$2,305	$0	$454	$0	$0	$2,759	$241	$0	$450	$3,449	$6
2.2	Coal Conveyor to Storage	$5,901	$0	$1,301	$0	$0	$7,203	$630	$0	$1,175	$9,007	$16
2.3	Coal Injection System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.4	Misc.Coal Prep & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.5	Sorbent Prep Equipment	$4,391	$188	$922	$0	$0	$5,501	$479	$0	$897	$6,878	$13
2.6	Sorbent Storage & Feed	$529	$0	$205	$0	$0	$734	$65	$0	$120	$919	$2
2.7	Sorbent Injection System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.8	Booster Air Supply System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.9	Coal & Sorbent Feed Foundation	$0	$570	$444	$0	$0	$1,014	$93	$0	$166	$1,274	$2
	SUBTOTAL 2.	**$13,126**	**$758**	**$3,326**	**$0**	**$0**	**$17,210**	**$1,508**	**$0**	**$2,808**	**$21,527**	**$39**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	$22,090	$0	$7,230	$0	$0	$29,320	$2,567	$0	$4,783	$36,670	$67
3.2	Water Makeup & Pretreating	$7,572	$0	$2,435	$0	$0	$10,007	$938	$0	$2,189	$13,134	$24
3.3	Other Feedwater Subsystems	$6,826	$0	$2,896	$0	$0	$9,722	$866	$0	$1,588	$12,176	$22
3.4	Service Water Systems	$1,495	$0	$807	$0	$0	$2,301	$214	$0	$503	$3,018	$6
3.5	Other Boiler Plant Systems	$8,357	$0	$8,175	$0	$0	$16,533	$1,551	$0	$2,713	$20,796	$38
3.6	FO Supply Sys & Nat Gas	$267	$0	$329	$0	$0	$596	$55	$0	$98	$749	$1
3.7	Waste Treatment Equipment	$5,103	$0	$2,923	$0	$0	$8,027	$778	$0	$1,761	$10,565	$19
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	$2,768	$0	$853	$0	$0	$3,621	$348	$0	$794	$4,762	$9
	SUBTOTAL 3.	**$54,477**	**$0**	**$25,648**	**$0**	**$0**	**$80,126**	**$7,317**	**$0**	**$14,428**	**$101,870**	**$187**
4	PC BOILER											
4.1	PC Boiler & Accessories	$190,969	$0	$107,678	$0	$0	$298,647	$28,927	$0	$32,757	$360,332	$660
4.2	SCR (w/4.1)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.3	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.4	Boiler BoP (w/ ID Fans)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.5	Primary Air System	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.6	Secondary Air System	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.8	Major Component Rigging	$0	w/4.1	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.9	Boiler Foundations	$0	w/14.1	w/14.1	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 4.	**$190,969**	**$0**	**$107,678**	**$0**	**$0**	**$298,647**	**$28,927**	**$0**	**$32,757**	**$360,332**	**$660**

Exhibit 4-44 Case 12 Total Plant Cost Details (Continued)

	Client:	USDOE/NETL							Report Date:	09-May-07		
	Project:	Bituminous Baseline Study										
		TOTAL PLANT COST SUMMARY										
	Case:	Case 12 - Supercritical PC w/ CO2										
	Plant Size:	546.0 MW,net		Estimate Type:		Conceptual			Cost Base (Dec)	2006	($x1000)	

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5	FLUE GAS CLEANUP											
5.1	Absorber Vessels & Accessories	$70,491	$0	$15,186	$0	$0	$85,677	$8,109	$0	$9,379	$103,165	$189
5.2	Other FGD	$3,679	$0	$4,172	$0	$0	$7,850	$756	$0	$861	$9,467	$17
5.3	Bag House & Accessories	$20,751	$0	$13,179	$0	$0	$33,931	$3,245	$0	$3,718	$40,894	$75
5.4	Other Particulate Removal Materials	$1,404	$0	$1,504	$0	$0	$2,908	$280	$0	$319	$3,507	$6
5.5	Gypsum Dewatering System	$5,422	$0	$922	$0	$0	$6,344	$599	$0	$694	$7,638	$14
5.6	Mercury Removal System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5.9	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 5.	**$101,747**	**$0**	**$34,963**	**$0**	**$0**	**$136,710**	**$12,990**	**$0**	**$14,970**	**$164,670**	**$302**
5B	CO_2 REMOVAL & COMPRESSION											
5B.1	CO_2 Removal System	$202,944	$0	$61,453	$0	$0	$264,397	$25,093	$52,879	$68,474	$410,843	$752
5B.2	CO_2 Compression & Drying	$26,888	$0	$8,398	$0	$0	$35,286	$3,350	$0	$7,727	$46,363	$85
	SUBTOTAL 5.	**$229,832**	**$0**	**$69,851**	**$0**	**$0**	**$299,683**	**$28,443**	**$52,879**	**$76,201**	**$457,207**	**$837**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
6.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.3	Compressed Air Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.9	Combustion Turbine Foundations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 6.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
7.2	HRSG Accessories	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$9,280	$0	$6,057	$0	$0	$15,337	$1,340	$0	$2,501	$19,178	$35
7.4	Stack	$8,609	$0	$5,041	$0	$0	$13,650	$1,304	$0	$1,495	$16,450	$30
7.9	Duct & Stack Foundations	$0	$981	$1,123	$0	$0	$2,104	$196	$0	$460	$2,760	$5
	SUBTOTAL 7.	**$17,889**	**$981**	**$12,221**	**$0**	**$0**	**$31,091**	**$2,840**	**$0**	**$4,457**	**$38,388**	**$70**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$53,763	$0	$7,192	$0	$0	$60,956	$5,836	$0	$6,679	$73,471	$135
8.2	Turbine Plant Auxiliaries	$368	$0	$789	$0	$0	$1,158	$112	$0	$127	$1,397	$3
8.3	Condenser & Auxiliaries	$5,563	$0	$1,956	$0	$0	$7,519	$715	$0	$823	$9,057	$17
8.4	Steam Piping	$20,992	$0	$10,369	$0	$0	$31,362	$2,617	$0	$5,097	$39,076	$72
8.9	TG Foundations	$0	$1,148	$1,827	$0	$0	$2,975	$280	$0	$651	$3,906	$7
	SUBTOTAL 8.	**$80,687**	**$1,148**	**$22,134**	**$0**	**$0**	**$103,969**	**$9,561**	**$0**	**$13,377**	**$126,907**	**$232**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$15,181	$0	$4,731	$0	$0	$19,911	$1,890	$0	$2,180	$23,982	$44
9.2	Circulating Water Pumps	$3,928	$0	$285	$0	$0	$4,213	$361	$0	$457	$5,031	$9
9.3	Circ.Water System Auxiliaries	$907	$0	$121	$0	$0	$1,028	$97	$0	$112	$1,237	$2
9.4	Circ.Water Piping	$0	$7,315	$6,977	$0	$0	$14,292	$1,317	$0	$2,341	$17,950	$33
9.5	Make-up Water System	$740	$0	$981	$0	$0	$1,721	$163	$0	$283	$2,167	$4
9.6	Component Cooling Water Sys	$723	$0	$571	$0	$0	$1,294	$121	$0	$212	$1,628	$3
9.9	Circ.Water System Foundations& Structures	$0	$3,884	$6,215	$0	$0	$10,099	$951	$0	$2,210	$13,260	$24
	SUBTOTAL 9.	**$21,479**	**$11,200**	**$19,881**	**$0**	**$0**	**$52,559**	**$4,900**	**$0**	**$7,796**	**$65,255**	**$120**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Ash Coolers	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.2	Cyclone Ash Letdown	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.3	HGCU Ash Letdown	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.4	High Temperature Ash Piping	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.5	Other Ash Recovery Equipment	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$685	$0	$2,113	$0	$0	$2,799	$273	$0	$307	$3,379	$6
10.7	Ash Transport & Feed Equipment	$4,468	$0	$4,548	$0	$0	$9,016	$853	$0	$987	$10,856	$20
10.8	Misc. Ash Handling Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.9	Ash/Spent Sorbent Foundation	$0	$162	$192	$0	$0	$354	$33	$0	$77	$464	$1
	SUBTOTAL 10.	**$5,154**	**$162**	**$6,854**	**$0**	**$0**	**$12,169**	**$1,158**	**$0**	**$1,371**	**$14,699**	**$27**

Exhibit 4-44 Case 12 Total Plant Cost Details (Continued)

	Client:	USDOE/NETL									Report Date:	09-May-07		
	Project:	Bituminous Baseline Study												
				TOTAL PLANT COST SUMMARY										
	Case:	Case 12 - Supercritical PC w/ CO2												
	Plant Size:	546.0 MW,net		Estimate Type:		Conceptual				Cost Base (Dec)	2006	($x1000)		
Acct No.	**Item/Description**	**Equipment Cost**	**Material Cost**	**Labor Direct**	**Labor Indirect**	**Sales Tax**	**Bare Erected Cost $**	**Eng'g CM H.O.& Fee**	**Contingencies Process**	**Contingencies Project**	**TOTAL PLANT COST $**	**TOTAL PLANT COST $/kW**		
11	ACCESSORY ELECTRIC PLANT													
11.1	Generator Equipment	$1,647	$0	$270	$0	$0	$1,917	$178	$0	$157	$2,251	$4		
11.2	Station Service Equipment	$4,617	$0	$1,581	$0	$0	$6,197	$593	$0	$509	$7,299	$13		
11.3	Switchgear & Motor Control	$5,487	$0	$940	$0	$0	$6,427	$595	$0	$702	$7,724	$14		
11.4	Conduit & Cable Tray	$0	$3,523	$11,989	$0	$0	$15,512	$1,485	$0	$2,549	$19,546	$36		
11.5	Wire & Cable	$0	$6,390	$12,630	$0	$0	$19,020	$1,603	$0	$3,093	$23,716	$43		
11.6	Protective Equipment	$243	$0	$861	$0	$0	$1,104	$108	$0	$121	$1,333	$2		
11.7	Standby Equipment	$1,253	$0	$30	$0	$0	$1,282	$121	$0	$140	$1,544	$3		
11.8	Main Power Transformers	$6,950	$0	$182	$0	$0	$7,132	$542	$0	$767	$8,441	$15		
11.9	Electrical Foundations	$0	$326	$806	$0	$0	$1,133	$108	$0	$248	$1,488	$3		
	SUBTOTAL 11.	**$20,196**	**$10,240**	**$29,287**	**$0**	**$0**	**$59,723**	**$5,331**	**$0**	**$8,288**	**$73,343**	**$134**		
12	INSTRUMENTATION & CONTROL													
12.1	PC Control Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0		
12.2	Combustion Turbine Control	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0		
12.3	Steam Turbine Control	w/8.1	$0	w/8.1	$0	$0	$0	$0	$0	$0	$0	$0		
12.4	Other Major Component Control	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
12.5	Signal Processing Equipment	W/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0		
12.6	Control Boards,Panels & Racks	$471	$0	$294	$0	$0	$765	$74	$38	$131	$1,008	$2		
12.7	Distributed Control System Equipment	$4,754	$0	$866	$0	$0	$5,620	$535	$281	$644	$7,080	$13		
12.8	Instrument Wiring & Tubing	$2,626	$0	$5,327	$0	$0	$7,953	$677	$398	$1,354	$10,382	$19		
12.9	Other I & C Equipment	$1,343	$0	$3,176	$0	$0	$4,520	$440	$226	$519	$5,704	$10		
	SUBTOTAL 12.	**$9,195**	**$0**	**$9,662**	**$0**	**$0**	**$18,857**	**$1,726**	**$943**	**$2,648**	**$24,174**	**$44**		
13	IMPROVEMENTS TO SITE													
13.1	Site Preparation	$0	$53	$1,071	$0	$0	$1,124	$111	$0	$247	$1,482	$3		
13.2	Site Improvements	$0	$1,765	$2,208	$0	$0	$3,973	$390	$0	$873	$5,236	$10		
13.3	Site Facilities	$3,162	$0	$3,142	$0	$0	$6,305	$619	$0	$1,385	$8,308	$15		
	SUBTOTAL 13.	**$3,162**	**$1,818**	**$6,421**	**$0**	**$0**	**$11,402**	**$1,120**	**$0**	**$2,504**	**$15,026**	**$28**		
14	BUILDINGS & STRUCTURES													
14.1	Boiler Building	$0	$8,384	$7,472	$0	$0	$15,857	$1,424	$0	$2,592	$19,873	$36		
14.2	Turbine Building	$0	$12,152	$11,477	$0	$0	$23,629	$2,128	$0	$3,864	$29,621	$54		
14.3	Administration Building	$0	$608	$651	$0	$0	$1,259	$114	$0	$206	$1,579	$3		
14.4	Circulation Water Pumphouse	$0	$279	$225	$0	$0	$503	$45	$0	$82	$631	$1		
14.5	Water Treatment Buildings	$0	$999	$834	$0	$0	$1,833	$164	$0	$300	$2,297	$4		
14.6	Machine Shop	$0	$406	$277	$0	$0	$683	$61	$0	$112	$855	$2		
14.7	Warehouse	$0	$275	$280	$0	$0	$555	$50	$0	$91	$696	$1		
14.8	Other Buildings & Structures	$0	$225	$194	$0	$0	$419	$38	$0	$69	$525	$1		
14.9	Waste Treating Building & Str.	$0	$431	$1,325	$0	$0	$1,756	$166	$0	$288	$2,210	$4		
	SUBTOTAL 14.	**$0**	**$23,760**	**$22,735**	**$0**	**$0**	**$46,495**	**$4,189**	**$0**	**$7,603**	**$58,287**	**$107**		
	TOTAL COST	**$767,230**	**$55,282**	**$382,352**	**$0**	**$0**	**$1,204,865**	**$113,256**	**$53,822**	**$195,130**	**$1,567,073**	**$2,870**		

Exhibit 4-45 Case 12 Initial and Annual Operating and Maintenance Costs

INITIAL & ANNUAL O&M EXPENSES					Cost Base (Dec)	2006
Case 12 - Supercritical PC w/ CO2					Heat Rate-net(Btu/kWh):	12,534
					MWe-net:	546
					Capacity Factor: (%):	85
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate(base):	33.00	$/hour				
Operating Labor Burden:	30.00	% of base				
Labor O-H Charge Rate:	25.00	% of labor				
			Total			
Skilled Operator	2.0		2.0			
Operator	11.3		11.3			
Foreman	1.0		1.0			
Lab Tech's, etc.	2.0		2.0			
TOTAL-O.J.'s	16.3		16.3			
					Annual Cost $	Annual Unit Cost $/kW-net
Annual Operating Labor Cost					$6,138,007	$11.242
Maintenance Labor Cost					$10,271,860	$18.813
Administrative & Support Labor					$4,102,467	$7.514
TOTAL FIXED OPERATING COSTS					**$20,512,333**	**$37.569**
VARIABLE OPERATING COSTS						
						$/kWh-net
Maintenance Material Cost					**$15,407,790**	**$0.00379**
Consumables	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost		
Water(/1000 gallons)	0	8,755	1.03	**$0**	**$2,797,790**	**$0.00069**
Chemicals						
MU & WT Chem.(lb)	296,665	42,381	0.16	$48,890	$2,166,895	$0.00053
Limestone (ton)	4,877	697	20.60	$100,457	$4,452,382	$0.00110
Carbon (Mercury Removal) (lb)	0	0	1.00	$0	$0	$0.00000
MEA Solvent (ton)	1,065	1.51	2,142.40	$2,281,656	$1,004,996	$0.00025
NaOH (tons)	74	7.36	412.96	$30,559	$942,457	$0.00023
H2SO4 (tons)	72	7.18	132.15	$9,515	$294,213	$0.00007
Corrosion Inhibitor	0	0	0.00	$147,250	$7,000	$0.00000
Activated Carbon(lb)	657,450	1,800	1.00	$657,450	$558,450	$0.00014
Ammonia (28% NH3) ton	813	116	123.60	$100,439	$4,451,615	$0.00109
Subtotal Chemicals				**$3,376,216**	**$13,878,007**	**$0.00341**
Other						
Supplemental Fuel(MBtu)	0	0	0.00	$0	$0	$0.00000
SCR Catalyst(m3)	w/equip.	0.62	5,500.00	$0	$1,058,976	$0.00026
Emission Penalties	0	0	0.00	$0	$0	$0.00000
Subtotal Other				**$0**	**$1,058,976**	**$0.00026**
Waste Disposal						
Flyash (ton)	0	137	15.45	$0	$654,409	$0.00016
Bottom Ash(ton)	0	546	15.45	$0	$2,617,579	$0.00064
Subtotal-Waste Disposal				**$0**	**$3,271,988**	**$0.00080**
By-products & Emissions						
Gypsum (tons)	0	1,085	0.00	$0	$0	$0.00000
Subtotal By-Products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$3,376,216**	**$36,414,550**	**$0.00896**
Fuel(ton)	211,183	7,039	42.11	$8,892,927	**$91,967,691**	**$0.02262**

4.4 PC CASE SUMMARY

The performance results of the four PC plant configurations modeled in this study are summarized in Exhibit 4-46.

Exhibit 4-46 Estimated Performance and Cost Results for Pulverized Coal Cases

	Pulverized Coal Boiler			
	PC Subcritical		PC Supercritical	
	Case 9	Case 10	Case 11	Case 12
CO_2 Capture	No	Yes	No	Yes
Gross Power Output (kW_e)	583,315	679,923	580,260	663,445
Auxiliary Power Requirement (kW_e)	32,870	130,310	30,110	117,450
Net Power Output (kW_e)	550,445	549,613	550,150	545,995
Coal Flowrate (lb/hr)	437,699	646,589	411,282	586,627
Natural Gas Flowrate (lb/hr)	N/A	N/A	N/A	N/A
HHV Thermal Input (kW_{th})	1,496,479	2,210,668	1,406,161	2,005,660
Net Plant HHV Efficiency (%)	36.8%	24.9%	39.1%	27.2%
Net Plant HHV Heat Rate (Btu/kW-hr)	9,276	13,724	8,721	12,534
Raw Water Usage, gpm	6,212	12,187	5,441	10,444
Total Plant Cost ($ x 1,000)	852,612	1,591,277	866,391	1,567,073
Total Plant Cost ($/kW)	1,549	2,895	1,575	2,870
LCOE (mills/kWh)[1]	64.0	118.8	63.3	114.8
CO_2 Emissions (lb/MWh)[2]	1,780	225	1,681	209
CO_2 Emissions (lb/MWh)[3]	1,886	278	1,773	254
SO_2 Emissions (lb/MWh)[2]	0.7426	Negligible	0.7007	Negligible
NOx Emissions (lb/MWh)[2]	0.613	0.777	0.579	0.722
PM Emissions (lb/MWh)[2]	0.114	0.144	0.107	0.134
Hg Emissions (lb/MWh)[2]	1.00E-05	1.27E-05	9.45E-06	1.18E-05

[1] Based on an 85% capacity factor
[2] Value is based on gross output
[3] Value is based on net output

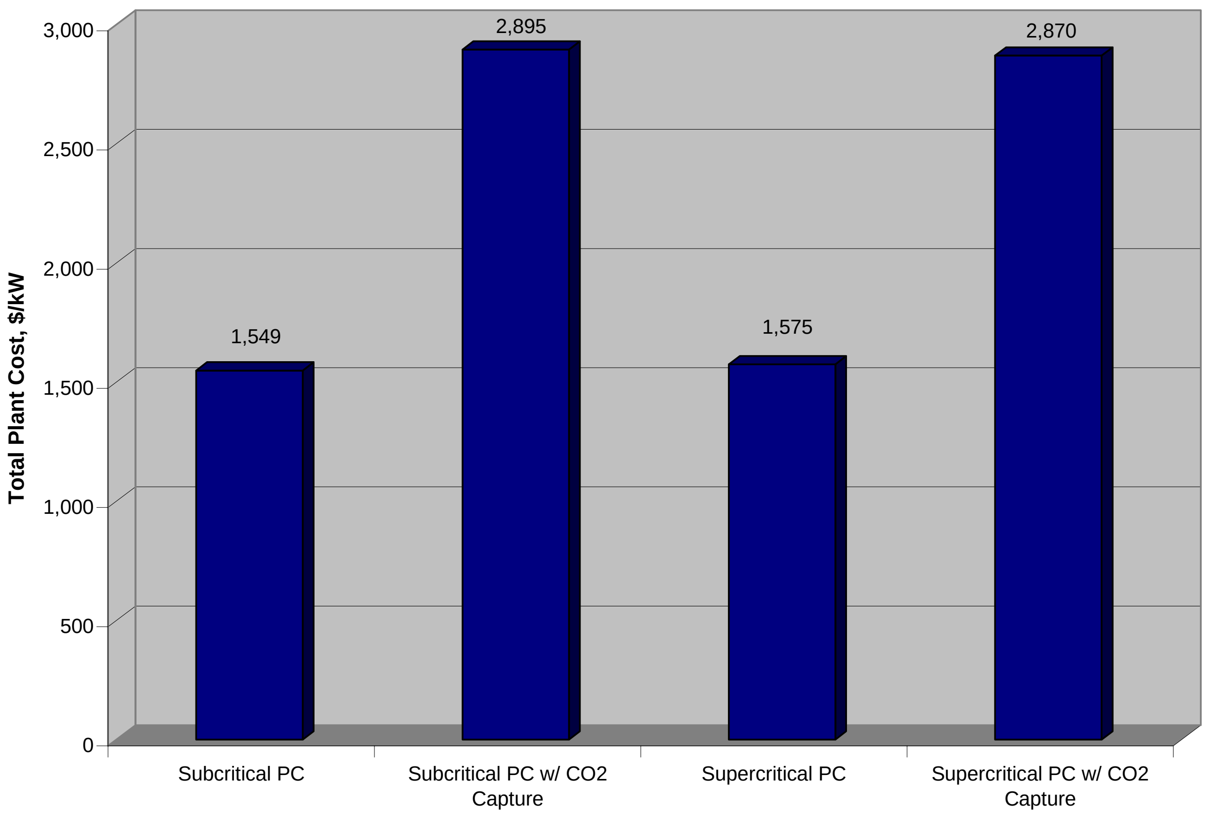
The TPC for each of the PC cases is shown in Exhibit 4-47.

The following observations can be made:

- The TPC of the non-capture supercritical PC case is only incrementally greater than subcritical PC (less than 2 percent). The TPC of supercritical PC with CO_2 capture is 0.9 percent less than subcritical PC.
- The capital cost penalty for adding CO_2 capture in the subcritical case is 87 percent and in the supercritical case is 82 percent. The Econamine FG Plus cost includes a process contingency of approximately $100/kW in both the subcritical and supercritical cases. Eliminating the process contingency results in a CO_2 capture cost penalty of 76 and 80 percent for the supercritical and subcritical PC cases, respectively. In addition to the high cost of the Econamine process, there is a significant increase in the cost of the cooling towers and circulating water pumps in the CO_2 capture cases because of the larger cooling water demand discussed previously. In addition, the gross output of the two PC plants increases by 97 MW (subcritical) and 83 MW (supercritical) to maintain the net

output at 550 MW. The increased gross output results in higher coal flow rate and consequent higher costs for all cost accounts in the estimate.

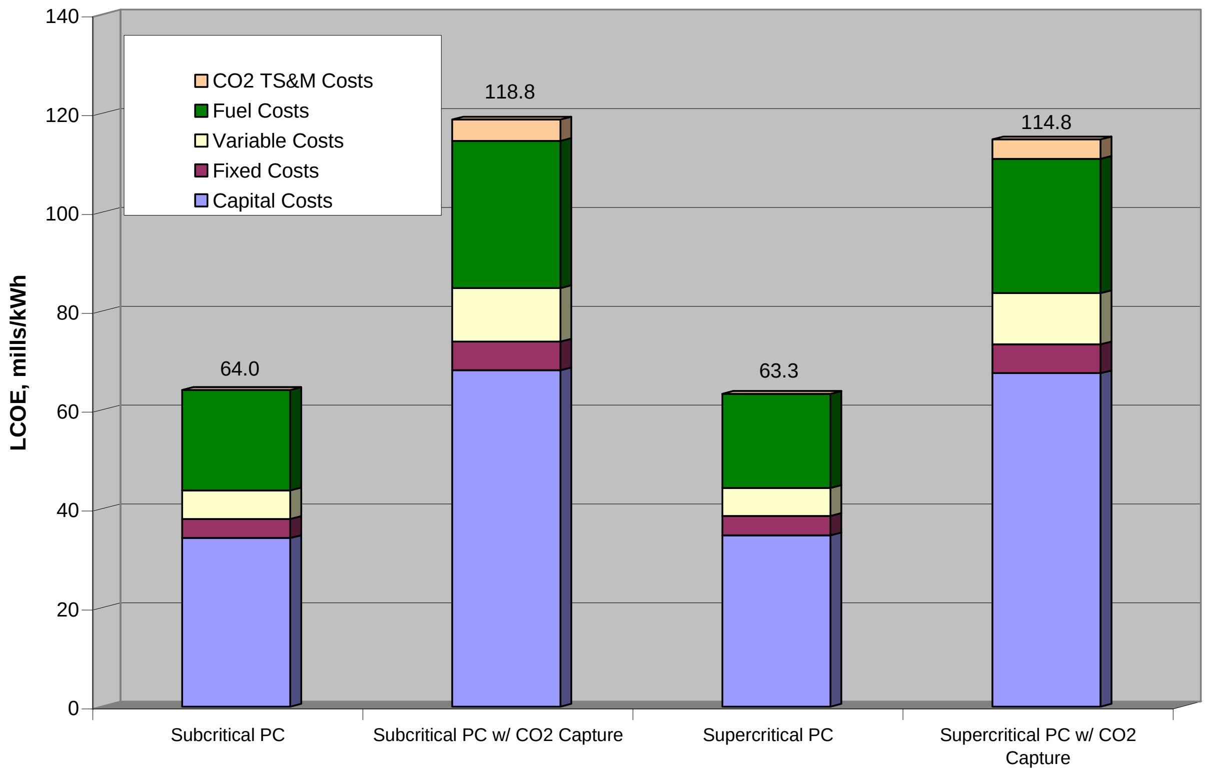
Exhibit 4-47 Total Plant Cost for PC Cases



The LCOE is shown for the four PC cases in Exhibit 4-48. The following observations can be made:

- Capital costs represent the largest fraction of LCOE in all cases, but particularly so in the CO_2 capture cases. Fuel cost is the second largest component of LCOE, and capital charges and fuel costs combined represent about 83 percent of the total in all cases.
- In the non-capture case the slight increase in capital cost in the supercritical case is more than offset by the efficiency gain so that the LCOE for supercritical PC is 1 percent less than subcritical despite having a nearly 2 percent higher TPC.
- In the CO_2 capture case, the cost differential between subcritical and supercritical PC is negligible (less than 1 percent), but the supercritical PC has a 3 percent lower LCOE because of the higher efficiency.

Exhibit 4-48 LCOE for PC Cases



The sensitivity of LCOE to capacity factor is shown in Exhibit 4-49. Implicit in the curves is the assumption that an efficiency of greater than 85 percent can be achieved without the expenditure of additional capital. The subcritical and supercritical cases with no CO_2 capture are nearly identical making it difficult to distinguish between the two lines. The LCOE increases more steeply at low capacity factor because the relatively high capital component is spread over fewer kilowatt-hours of generation.

The sensitivity of LCOE to coal price is shown in Exhibit 4-50. As in the IGCC cases, the LCOE in the PC cases is relatively insensitive to coal price.

As presented in Section 2.4 the cost of CO_2 capture was calculated in two ways, CO_2 removed and CO_2 avoided. The results for the PC carbon capture cases are shown in Exhibit 4-51.

The cost of CO_2 captured and avoided is nearly identical for the subcritical and supercritical PC cases. The avoided cost is significantly higher than the captured cost because the gross output of the capture case is 83-96 MW higher than the non-capture case which reduces the amount of CO_2 avoided between cases.

Exhibit 4-49 Sensitivity of LCOE to Capacity Factor for PC Cases

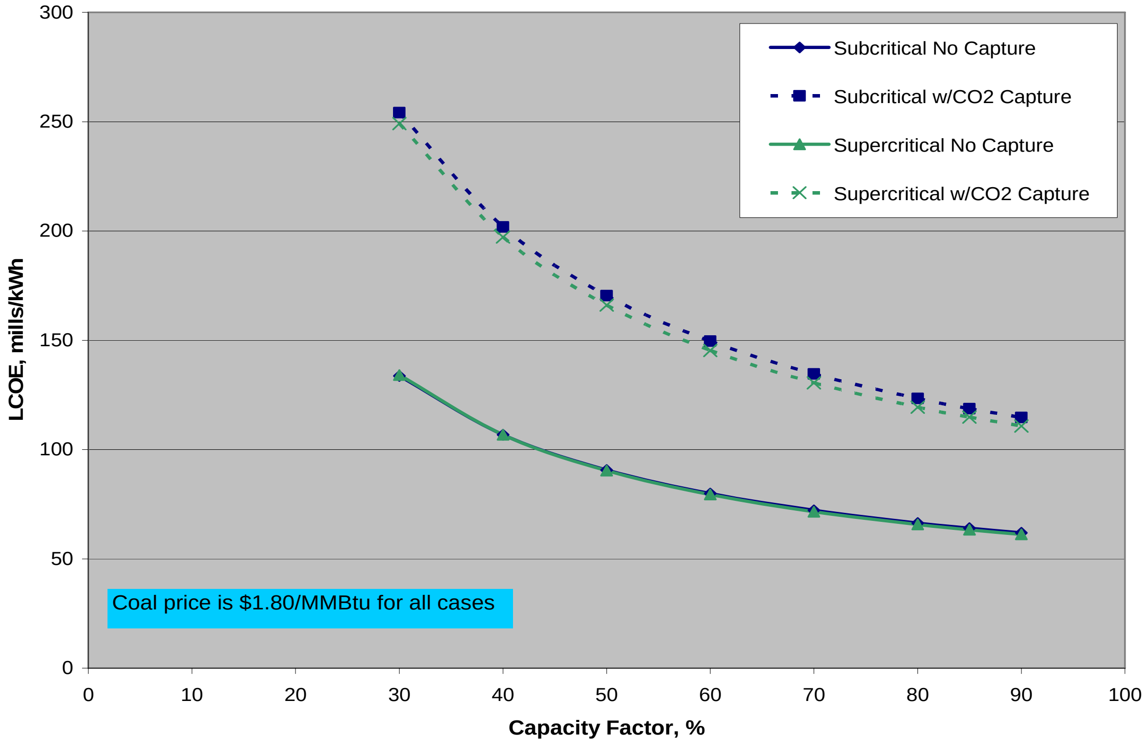


Exhibit 4-50 Sensitivity of LCOE to Coal Price for PC Cases

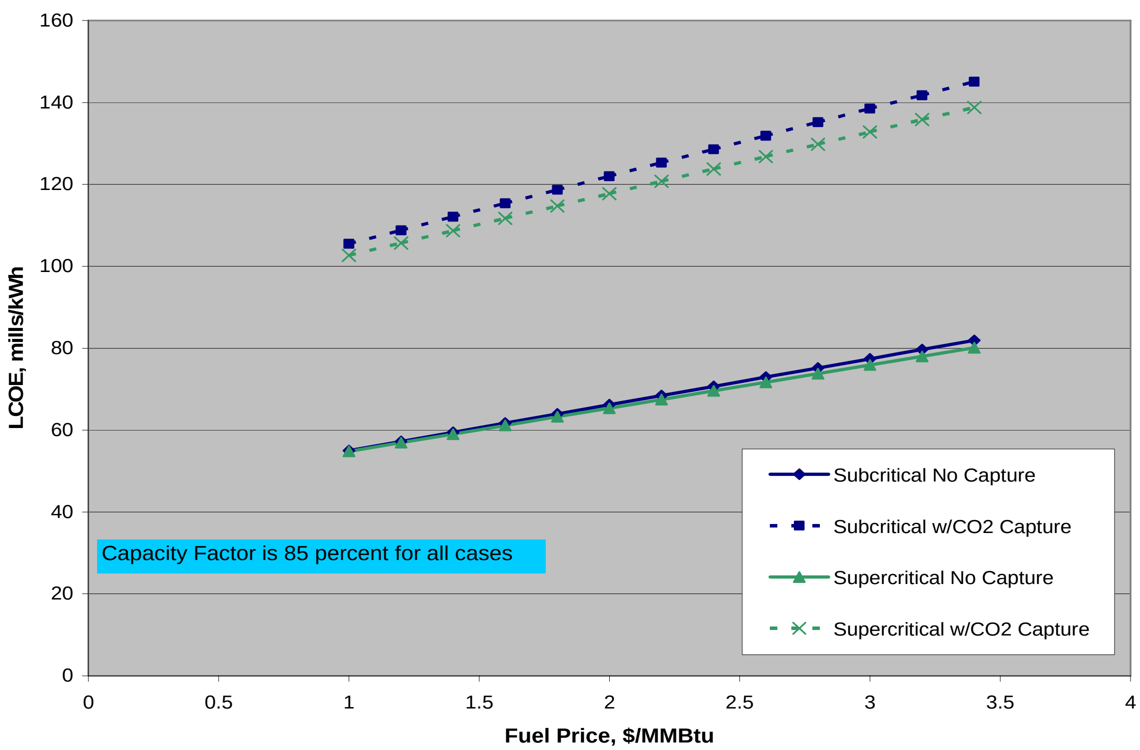
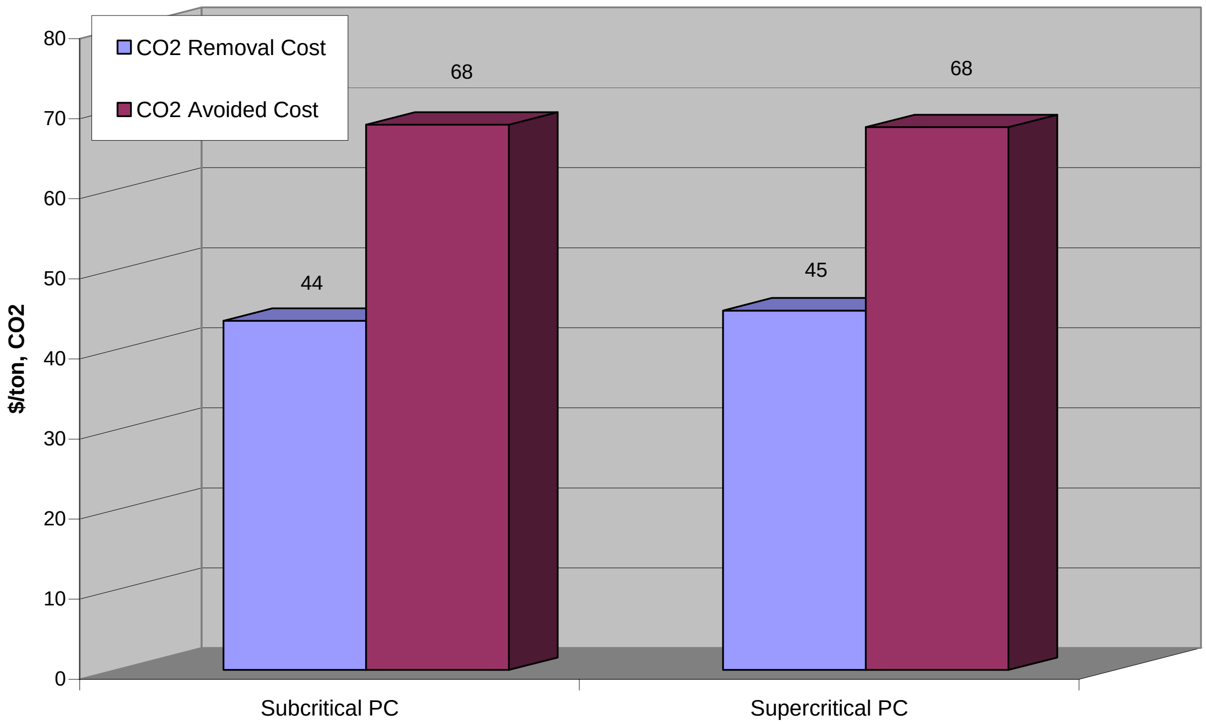


Exhibit 4-51 Cost of CO_2 Captured and Avoided in PC Cases



The following observations can be made regarding plant performance with reference to Exhibit 4-46:

- The efficiency of the supercritical PC plant is 2.3 percentage points higher than than the equivalent subcritical PC plant (39.1 percent compared to 36.8 percent). The efficiencies are comparable to those reported in other studies once steam cycle conditions are considered. For example, in an EPA study [62] comparing PC and IGCC plant configurations the subcritical PC plant using bituminous coal had an efficiency of 35.9 percent with a steam cycle of 16.5 MPa/538°C/538°C (2400 psig/1000°F/1000°F). The higher steam cycle temperature in this study 566°C/566°C (1050°F/1050°F) results in a higher net efficiency. The same study reported a supercritical plant efficiency of 38.3 percent with a steam cycle of 24.1 MPa/566°C/566°C (3500 psig/1050°F/1050°F). Again, the more aggressive steam conditions in this study, 593°C/593°C (1100°F/1100°F) resulted in a higher net efficiency.

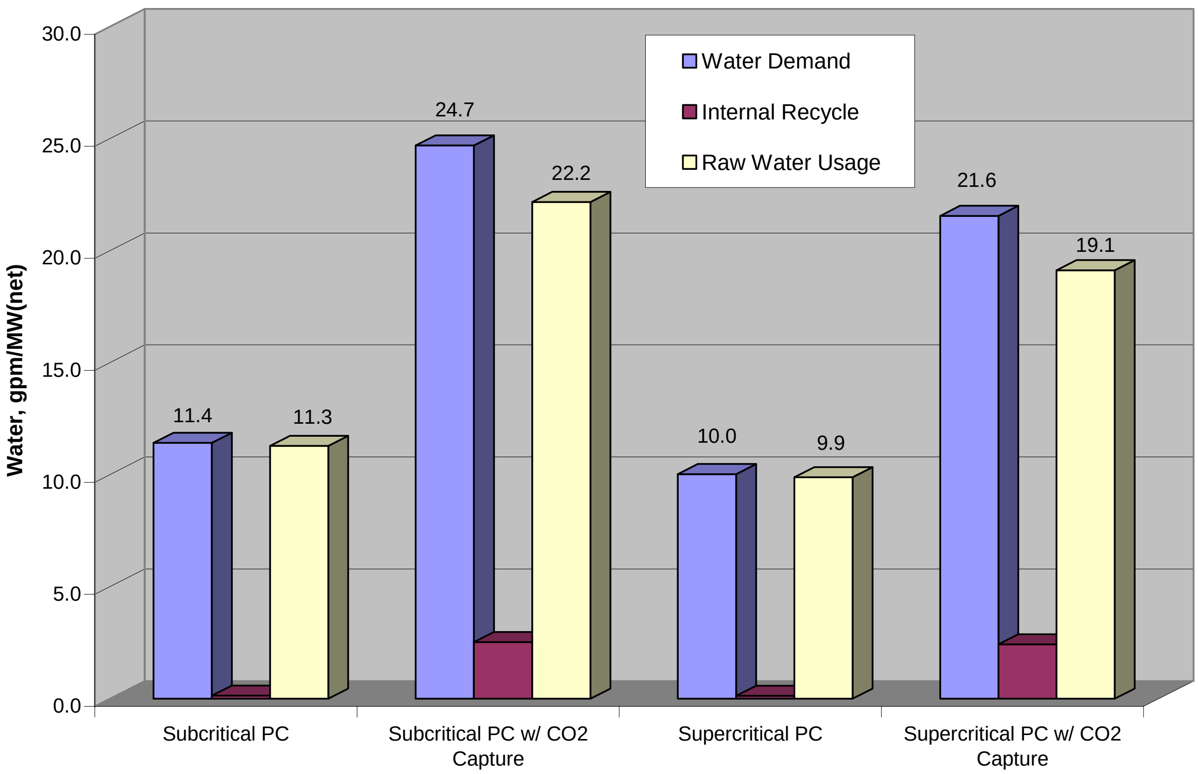
  Similar results from an EPRI study using Illinois No. 6 coal were reported as follows [63]:

  - Subcritical PC efficiency of 35.7 percent with a steam cycle of 16.5 MPa/538°C/538°C (2400 psig/1000°F/1000°F).
  - Supercritical PC efficiency of 38.3 percent with a steam cycle of 24.8 MPa/593°C/593°C (3600 psig/1100°F/1100°F).

- The addition of CO_2 capture to the two PC cases results in the same absolute efficiency impact, namely an 11.9 percentage point decrease. The efficiency is negatively impacted by the large auxiliary loads of the Econamine process and CO_2 compression, as well as the large increase in cooling water requirement, which increases the circulating water pump and cooling tower fan auxiliary loads. The auxiliary load increases by 97 MW in the subcritical PC case and by 87 MW in the supercritical PC case.
- NOx, PM and Hg emissions are the same for all four PC cases on a heat input basis because of the environmental target assumptions of fixed removal efficiencies for each case (86 percent SCR efficiency, 99.8 percent baghouse efficiency and 90 percent co-benefit capture). The emissions on a mass basis or normalized by gross output are higher for subcritical cases than supercritical cases and are higher for CO_2 capture cases than non-capture cases because of the higher efficiencies of supercritical PC and non-capture PC cases.
- SO_2 emissions are likewise constant on a heat input basis for the non-capture cases, but the Econamine process polishing scrubber and absorber vessel result in negligible SO_2 emissions in CO_2 capture cases. The SO_2 emissions for subcritical PC are higher than supercritical on a mass basis and when normalized by gross output because of the lower efficiency.
- Uncontrolled CO_2 emissions on a mass basis are greater for subcritical PC compared to supercritical because of the lower efficiency. The capture cases result in a 90% reduction of CO_2 for both subcritical and supercritical PC.
- Raw water usage for all cases is dominated by cooling tower makeup requirements, which accounts for about 89 percent of raw water in non-capture cases and 92 percent of raw water in CO_2 capture cases. The amount of raw water usage in the CO_2 capture cases is greatly increased by the cooling water requirements of the Econamine process. Cooling water is required to:
    - Reduce the flue gas temperature from 57°C (135°F) (FGD exit temperature) to 32°C (89°F) (Econamine absorber operating temperature), which also requires condensing water from the flue gas that comes saturated from the FGD unit.
    - Remove the heat input by the stripping steam to cool the solvent
    - Remove the heat input from the auxiliary electric loads
    - Remove heat in the CO_2 compressor intercoolers

The normalized water demand, internal recycle and raw water usage are shown in Exhibit 4-52 for each of the PC cases. The only internal recycle stream that affects the overall balance in the non-capture cases is the boiler feedwater blowdown stream which is recycled to the cooling tower as makeup water. In the CO_2 capture cases, additional water is recovered from the flue gas as it is cooled to the absorber temperature of 32°C (89°F). The condensate is treated and also used as cooling tower makeup.

Exhibit 4-52 Water Usage in PC Cases



5 NATURAL GAS COMBINED CYCLE PLANTS

Two natural gas combined cycle (NGCC) power plant configurations were evaluated and are presented in this section. Each design is based on a market-ready technology that is assumed to be commercially available in time to support a 2010 start up date. Each design consists of two advanced F class combustion turbine generators (CTG), two HRSG's and one steam turbine generator (STG) in a multi-shaft 2x2x1 configuration.

The NGCC cases are evaluated with and without carbon capture on a common thermal input basis. The NGCC designs that include CDR have a smaller plant net output resulting from the additional CDR facility auxiliary loads. Like in the IGCC cases, the sizes of the NGCC designs were determined by the output of the commercially available combustion turbine. Hence, evaluation of the NGCC designs on a common net output basis was not possible.

The Rankine cycle portion of both designs uses a single reheat 16.5 MPa/566°C/510°C (2400 psig/1050°F/950°F) steam cycle. A more aggressive steam cycle was considered but not chosen because there are very few HRSGs in operation that would support such conditions. [54]

5.1 NGCC COMMON PROCESS AREAS

The two NGCC cases are nearly identical in configuration with the exception that Case 14 includes CO_2 capture while Case 13 does not. The process areas that are common to the two plant configurations are presented in this section.

5.1.1 NATURAL GAS SUPPLY SYSTEM

It was assumed that a natural gas main with adequate capacity is in close proximity (within 16 km [10 miles]) to the site fence line and that a suitable right of way is available to install a branch line to the site. For the purposes of this study it was also assumed that the gas will be delivered to the plant custody transfer point at 3.0 MPa (435 psig) and 38°C (100ºF), which matches the advanced F Class fuel system requirements. Hence, neither a pressure reducing station with gas preheating (to prevent moisture and hydrocarbon condensation), nor a fuel booster compressor are required.

A new gas metering station is assumed to be added on the site, adjacent to the new combustion turbine. The meter may be of the rate-of-flow type, with input to the plant computer for summing and recording, or may be of the positive displacement type. In either case, a complete time-line record of gas consumption rates and cumulative consumption is provided.

5.1.2 COMBUSTION TURBINE

The combined cycle plant is based on two CTG's. The combustion turbine generator is representative of the advanced F Class turbines with an ISO base rating of 184,400 kW when firing natural gas. [64] This machine is an axial flow, single spool, constant speed unit, with variable inlet guide vanes and dry LNB combustion system.

Each combustion turbine generator is provided with inlet air filtration systems; inlet silencers; lube and control oil systems including cooling; electric motor starting systems; acoustical enclosures including heating and ventilation; control systems including supervisory, fire protection, and fuel systems. No back up fuel was envisioned for this project.

The CTG is typically supplied in several fully shop-fabricated modules, complete with all mechanical, electrical, and control systems required for CTG operation. Site CTG installation involves module interconnection and linking CTG modules to the plant systems. The CTG package scope of supply for combined cycle application, while project specific, does not vary much from project-to-project. A typical scope of supply is presented in Exhibit 5-1.

Exhibit 5-1 Combustion Turbine Typical Scope of Supply

System	System Scope
ENGINE ASSEMBLY	Coupling to Generator, Dry Chemical Exhaust Bearing Fire Protection System, Insulation Blankets, Platforms, Stairs and Ladders
Engine Assembly with Bedplate	Variable Inlet Guide Vane System, Compressor, Bleed System, Purge Air System, Bearing Seal Air System, Combustors, Dual Fuel Nozzles, Turbine Rotor Cooler
Walk-in acoustical enclosure	HVAC, Lighting, and Low Pressure CO_2 Fire Protection System
MECHANICAL PACKAGE	HVAC and Lighting, Air Compressor for Pneumatic System, Low Pressure CO_2 Fire Protection System
Lubricating Oil System and Control Oil System	Lube Oil Reservoir, Accumulators, 2x100% AC Driven Oil Pumps, DC Emergency Oil Pump with Starter, 2x100% Oil Coolers, Duplex Oil Filter, Oil Temperature and Pressure Control Valves, Oil Vapor Exhaust Fans and Demister, Oil Heaters, Oil Interconnect Piping (SS and CS), Oil System Instrumentation, Oil for Flushing and First Filling
ELECTRICAL PACKAGE	HVAC and Lighting, AC and DC Motor Control Centers, Generator Voltage Regulating Cabinet, Generator Protective Relay Cabinet, DC Distribution Panel, Battery Charger, Digital Control System with Local Control Panel (all control and monitoring functions as well as data logger and sequence of events recorder), Control System Valves and Instrumentation Communication link for interface with plant DCS Supervisory System, Bentley Nevada Vibration Monitoring System, Low Pressure CO_2 Fire Protection System, Cable Tray and Conduit Provisions for Performance Testing including Test Ports, Thermowells, Instrumentation and DCS interface cards
INLET AND EXHAUST SYSTEMS	Inlet Duct Trash Screens, Inlet Duct and Silencers, Self Cleaning Filters, Hoist System For Filter Maintenance, Evaporative Cooler System, Exhaust Duct Expansion Joint, Exhaust Silencers Inlet and Exhaust Flow, Pressure and Temperature Ports and Instrumentation
FUEL SYSTEMS	
N. Gas System	Gas Valves Including Vent, Throttle and Trip Valves, Gas Filter/Separator, Gas Supply Instruments and Instrument Panel
STARTING SYSTEM	Enclosure, Starting Motor or Static Start System, Turning Gear and Clutch Assembly, Starting Clutch, Torque Converter
GENERATOR	Static or Rotating Exciter (Excitation transformer to be included for a static system), Line Termination Enclosure with CTs, VTs, Surge Arrestors, and Surge Capacitors, Neutral Cubicle with CT, Neutral Tie Bus, Grounding Transformer, and Secondary Resistor, Generator Gas Dryer, Seal Oil System (including Defoaming Tank, Reservoir, Seal Oil Pump, Emergency Seal Oil Pump, Vapor Extractor, and Oil Mist Eliminator), Generator Auxiliaries Control Enclosure, Generator Breaker, Iso-Phase bus connecting generator and breaker, Grounding System Connectors
Generator Cooling	TEWAC System (including circulation system, interconnecting piping and controls), or Hydrogen Cooling System (including H_2 to Glycol and Glycol to Air heat exchangers, liquid level detector circulation system, interconnecting piping and controls)
MISCELLANEOUS	Interconnecting Pipe, Wire, Tubing and Cable Instrument Air System Including Air Dryer On Line and Off Line Water Wash System LP CO_2 Storage Tank Drain System Drain Tanks Coupling, Coupling Cover and Associated Hardware

The generators would typically be provided with the combustion turbine package. The generators are assumed to be 24 kV, 3-phase, 60 hertz, constructed to meet American National Standards Institute (ANSI) and National Electrical Manufacturers Association (NEMA) standards for turbine-driven synchronous generators. The generator is totally enclosed, water-air cooled (TEWAC), complete with excitation system, cooling, and protective relaying.

5.1.3 HEAT RECOVERY STEAM GENERATOR

The HRSG is configured with HP, IP, and LP steam drums, and superheater, reheater, and economizer sections. The HP drum is supplied with feedwater by the HP boiler feed pump to generate HP steam, which passes to the superheater section for heating to 566°C (1050°F). The IP drum is supplied with feedwater from an interstage bleed on the HP boiler feed pump. The IP steam from the drum is superheated to 482°C (900°F) and mixed with hot reheat steam from the reheat section at 510°C (950ºF) and a portion of HP steam also at 510°C (950ºF). The combined flows are admitted into the IP section of the steam turbine. The LP drum provides steam to the integral deaerator, and also to the LP turbine.

The economizer sections heat condensate and feedwater (in separate tube bundles). The HRSG tubes are typically comprised of bare surface and/or finned tubing or pipe material. The high-temperature portions are type P91 or P22 ferritic alloy material; the low-temperature portions (< 399°C [750°F]) are carbon steel. Each HRSG exhausts directly to the stack, which is fabricated from carbon steel plate materials and lined with Type 409 stainless steel. The stack for the NGCC cases is assumed to be 46 m (150 ft) high, and the cost is included in the HRSG account.

5.1.4 NOX CONTROL SYSTEM

This reference plant is designed to achieve 2.5 ppmvd NOx emissions (expressed as NO_2 and referenced to 15 percent O_2). Two measures are taken to reduce the NOx. The first is a dry low NOx burner in the CTG. The dry LNB burners are a low NOx design and reduce the emissions to about 25 ppmvd (referenced to 15 percent O_2). [65]

The second measure taken to reduce the NOx emissions was the installation of a SCR system. SCR uses ammonia and a catalyst to reduce NOx to N_2 and H_2O. The SCR system consists of reactor, and ammonia supply and storage system. The SCR system is designed for 90 percent reduction while firing natural gas. This along with the dry LNB achieves the emission limit of 2.5 ppmvd (referenced to 15 percent O_2).

Operation Description - The SCR reactor is located in the flue gas path inside the HRSG between the high pressure and intermediate pressure sections. The SCR reactor is equipped with one catalyst layer consisting of catalyst modules stacked in line on a supporting structural frame. The SCR reactor has space for installation of an additional layer. Ammonia is injected into the gas immediately prior to entering the SCR reactor. The ammonia injection grid is arranged into several sections, and consists of multiple pipes with nozzles. Ammonia flow rate into each injection grid section is controlled taking into account imbalances in the flue gas flow distribution across the HRSG. The catalyst contained in the reactor enhances the reaction between the ammonia and the NOx in the gas. The catalyst consists of various active materials such as titanium dioxide, vanadium pentoxide, and tungsten trioxide. The optimum inlet flue gas temperature range for the catalyst is 260°C (500°F) to 343°C (650°F).

The ammonia storage and injection system consists of the unloading facilities, bulk storage tank, vaporizers, and dilution air skid.

5.1.5 CARBON DIOXIDE RECOVERY FACILITY

A CDR facility is used in Case 14 to remove 90 percent of the CO_2 in the flue gas exiting the HRSG, purify it, and compress it to a supercritical condition. It is assumed that all of the carbon in the natural gas is converted to CO_2. The CDR is comprised of flue gas supply, CO_2 absorption, solvent stripping and reclaiming, and CO_2 compression and drying.

The CO_2 absorption/stripping/solvent reclaim process for Case 14 is based on the Fluor Econamine FG Plus technology as previously described in Section 4.1.7 with the exception that no SO_2 polishing step is required in the NGCC case. If the pipeline natural gas used in this study contained the maximum amount of sulfur allowed per EPA specifications (0.6 gr S/100 scf), the flue gas would contain 0.4 ppmv of SO_2, which is well below the limit where a polishing scrubber would be required (10 ppmv). A description of the basic process steps is repeated here for completeness with minor modifications to reflect application in an NGCC system as opposed to PC.

Flue Gas Cooling and Supply

The function of the flue gas cooling and supply system is to transport flue gases from the HRSG to the CO_2 absorption tower, and condition flue gas pressure, temperature and moisture content so it meets the requirements of the Econamine process. Temperature and hence moisture content of the flue gas exiting the HRSG is reduced in the Direct Contact Flue Gas Cooler, where flue gas is cooled using cooling water.

The water condensed from the flue gas is collected in the bottom of the Direct Contact Flue Gas Cooler section and re-circulated to the top of the Direct Contact Flue Gas Cooler section via the Flue Gas Circulation Water Cooler, which rejects heat to the plant circulating water system. Level in the Direct Contact Flue Gas Cooler is controlled by directing the excess water to the cooling water return line. In the Direct Contact Flue Gas Cooler, flue gas is cooled beyond the CO_2 absorption process requirements to 33°C (91°F) to account for the subsequent flue gas temperature increase of 14°C (25°F) in the flue gas blower. Downstream from the Direct Contact Flue Gas Cooler flue gas pressure is boosted in the flue gas blowers by approximately 0.01 MPa (2 psi) to overcome pressure drop in the CO_2 absorber tower.

Circulating Water System

Cooling water is provided from the NGCC plant circulating water system and returned to the NGCC plant cooling tower. The CDR facility requires a significant amount of cooling water for flue gas cooling, water wash cooling, absorber intercooling, reflux condenser duty, reclaimer cooling, the lean solvent cooler, and CO_2 compression interstage cooling. The cooling water requirements for the CDR facility in the NGCC capture case is about 681,380 lpm (180,000 gpm), which greatly exceeds the NGCC plant cooling water requirement of about 227,125 lpm (60,000 gpm).

CO_2 Absorption

The cooled flue gas enters the bottom of the CO_2 Absorber and flows up through the tower countercurrent to a stream of lean MEA-based solvent called Econamine FG Plus. Approximately 90 percent of the CO_2 in the feed gas is absorbed into the lean solvent, and the rest leaves the top of the absorber section and flows into the water wash section of the tower. The lean solvent enters the top of the absorber, absorbs the CO_2 from the flue gases and leaves the bottom of the absorber with the absorbed CO_2.

Water Wash Section

The purpose of the Water Wash section is to minimize solvent losses due to mechanical entrainment and evaporation. The flue gas from the top of the CO_2 Absorption section is contacted with a re-circulating stream of water for the removal of most of the lean solvent. The scrubbed gases, along with unrecovered solvent, exit the top of the wash section for discharge to the atmosphere via the vent stack. The water stream from the bottom of the wash section is collected on a chimney tray. A portion of the water collected on the chimney tray spills over to the absorber section as water makeup for the amine with the remainder pumped via the Wash Water Pump and cooled by the Wash Water Cooler, and recirculated to the top of the CO_2 Absorber. The wash water level is maintained by water makeup from the Wash Water Makeup Pump.

Rich/Lean Amine Heat Exchange System

The rich solvent from the bottom of the CO_2 Absorber is preheated by the lean solvent from the Solvent Stripper in the Rich Lean Solvent Exchanger. The heated rich solvent is routed to the Solvent Stripper for removal of the absorbed CO_2. The stripped solvent from the bottom of the Solvent Stripper is pumped via the Hot Lean Solvent Pumps through the Rich Lean Exchanger to the Solvent Surge Tank. Prior to entering the Solvent Surge Tank, a slipstream of the lean solvent is pumped via the Solvent Filter Feed Pump through the Solvent Filter Package to prevent buildup of contaminants in the solution. From the Solvent Surge Tank the lean solvent is pumped via the Warm Lean Solvent Pumps to the Lean Solvent Cooler for further cooling, after which the cooled lean solvent is returned to the CO_2 Absorber, completing the circulating solvent circuit.

Solvent Stripper

The purpose of the Solvent Stripper is to separate the CO_2 from the rich solvent feed exiting the bottom of the CO_2 Absorber. The rich solvent is collected on a chimney tray below the bottom packed section of the Solvent Stripper and routed to the Solvent Stripper Reboilers where the rich solvent is heated by steam, stripping the CO_2 from the solution. Steam is provided from the LP section of the steam turbine at about 0.47 MPa (68 psia) and 291°C (555°F). The hot wet vapor from the top of the stripper containing CO_2, steam, and solvent vapor, is partially condensed in the Solvent Stripper Condenser by cross exchanging the hot wet vapor with cooling water. The partially condensed stream then flows to the Solvent Stripper Reflux Drum where the vapor and liquid are separated. The uncondensed CO_2-rich gas is then delivered to the CO_2 product compressor. The condensed liquid from the Solvent Stripper Reflux Drum is pumped via the Solvent Stripper Reflux Pumps where a portion of condensed overhead liquid is used as make-up water for the Water Wash section of the CO_2 Absorber. The rest of the pumped liquid is routed back to the Solvent Stripper as reflux, which aids in limiting the amount of solvent vapors entering the stripper overhead system.

Solvent Stripper Reclaimer

A small slipstream of the lean solvent from the Solvent Stripper bottoms is fed to the Solvent Stripper Reclaimer for the removal of high-boiling nonvolatile impurities (heat stable salts – HSS), volatile acids and iron products from the circulating solvent solution. The solvent bound in the HSS is recovered by reaction with caustic and heating with steam. The solvent reclaimer system reduces corrosion, foaming and fouling in the solvent system. The reclaimed solvent is returned to the Solvent Stripper and the spent solvent is pumped via the Solvent Reclaimer Drain Pump to the Solvent Reclaimer Drain Tank.

Steam Condensate

Steam condensate from the Solvent Stripper Reclaimer accumulates in the Solvent Reclaimer Condensate Drum and level controlled to the Solvent Reboiler Condensate Drum. Steam condensate from the Solvent Stripper Reboilers is also collected in the Solvent Reboiler Condensate Drum and returned to the steam cycle just downstream of the deaerator via the Solvent Reboiler Condensate Pumps.

Corrosion Inhibitor System

A proprietary corrosion inhibitor is continuously injected into the CO_2 Absorber rich solvent bottoms outlet line, the Solvent Stripper bottoms outlet line and the Solvent Stripper top tray. This constant injection is to help control the rate of corrosion throughout the CO_2 recovery plant system.

Gas Compression and Drying System

In the compression section, the CO_2 is compressed to 15.3 MPa (2,215 psia) by a six-stage centrifugal compressor. The discharge pressures of the stages were balanced to give reasonable power distribution and discharge temperatures across the various stages as shown in Exhibit 5-2.

Power consumption for this large compressor was estimated assuming an isentropic efficiency of 84 percent. During compression to 15.3 MPa (2,215 psia) in the multiple-stage, intercooled compressor, the CO_2 stream is dehydrated to a dewpoint of -40ºC (-40°F) with triethylene glycol. The virtually moisture-free supercritical CO_2 stream is delivered to the plant battery limit as sequestration ready. CO_2 TS&M costs were estimated and included in LCOE using the methodology described in Section 2.7.

5.1.6 STEAM TURBINE

The steam turbine consists of an HP section, an IP section, and one double-flow LP section, all connected to the generator by a common shaft. The HP and IP sections are contained in a single span, opposed-flow casing, with the double-flow LP section in a separate casing.

Main steam from the boiler passes through the stop valves and control valves and enters the turbine at 16.5 MPa/566°C (2400 psig/1050°F). The steam initially enters the turbine near the middle of the high-pressure span, flows through the turbine, and returns to the HRSG for reheating. The reheat steam flows through the reheat stop valves and intercept valves and enters the IP section at 2.3 MPa/510°C (328 psia/950°F). After passing through the IP section, the steam enters a cross-over pipe, which transports the steam to the LP section. A branch line equipped with combined stop/intercept valves conveys LP steam from the HRSG LP drum to a tie-in at the cross-over line. The steam divides into two paths and flows through the LP sections exhausting downward into the condenser.

Exhibit 5-2 CO_2 Compressor Interstage Pressures

Stage	Outlet Pressure, MPa (psia)
1	0.36 (52)
2	0.78 (113)
3	1.71 (248)
4	3.76 (545)
5	8.27 (1,200)
6	15.3 (2,215)

Turbine bearings are lubricated by a closed-loop, water-cooled pressurized oil system. Turbine shafts are sealed against air in-leakage or steam blowout using a modern positive pressure variable clearance shaft sealing design arrangement connected to a low-pressure steam seal system. The generator is a hydrogen-cooled synchronous type, generating power at 24 kV. A static, transformer type exciter is provided. The generator is cooled with a hydrogen gas recirculation system using fans mounted on the generator rotor shaft. The steam turbine generator is controlled by a triple-redundant microprocessor-based electro-hydraulic control system. The system provides digital control of the unit in accordance with programmed control algorithms, color monitor/operator interfacing, and datalink interfaces to the balance-of-plant distributed control system (DCS), and incorporates on-line repair capability.

5.1.7 WATER AND STEAM SYSTEMS

Condensate

The function of the condensate system is to pump condensate from the condenser hotwell to the deaerator, through the gland steam condenser; and the low-temperature economizer section in the HRSG.

The system consists of one main condenser; two 50 percent capacity, motor-driven vertical multistage condensate pumps (total of two pumps for the plant); one gland steam condenser; condenser air removal vacuum pumps, condensate polisher, and a low-temperature tube bundle in the HRSG.

Condensate is delivered to a common discharge header through two separate pump discharge lines, each with a check valve and a gate valve. A common minimum flow recirculation line discharging to the condenser is provided to maintain minimum flow requirements for the gland steam condenser and the condensate pumps.

Feedwater

The function of the feedwater (FW) system is to pump the various feedwater streams from the deaerator storage tank in the HRSG to the respective steam drums. One 100 percent capacity motor-driven feed pump is provided per each HRSG (total of two pumps for the plant). The FW pumps are equipped with an interstage takeoff to provide IP and LP feedwater. Each pump is provided with inlet and outlet isolation valves, outlet check valves, and individual minimum flow recirculation lines discharging back to the deaerator storage tank. The recirculation flow is controlled by pneumatic flow control valves. In addition, the suctions of the boiler feed pumps are equipped with startup strainers, which are utilized during initial startup and following major outages or system maintenance.

Steam System

The steam system is comprised of main, reheat, intermediate, and low-pressure steam systems. The function of the main steam system is to convey main steam from the HRSG superheater outlet to the HP turbine stop valves. The function of the reheat system is to convey steam from the HP turbine exhaust to the HRSG reheater and from the HRSG reheater outlet to the turbine reheat stop valves.

Main steam exits the HRSG superheater through a motor-operated stop/check valve and a motor-operated gate valve, and is routed to the HP turbine.

Cold reheat steam exits the HP turbine, and flows through a motor-operated isolation gate valve to the HRSG reheater. Hot reheat steam exits at the HRSG reheater through a motor-operated gate valve and is routed to the IP turbines.

Circulating Water System

The function of the circulating water system is to supply cooling water to condense the main turbine exhaust steam, for the auxiliary cooling system and for the CDR facility in Case 14. The system consists of two 50 percent capacity vertical circulating water pumps (total of two pumps for the plant), a mechanical draft evaporative cooling tower, and interconnecting piping. The condenser is a single pass, horizontal type with divided water boxes. There are two separate circulating water circuits in each box. One-half of the condenser can be removed from service for cleaning or plugging tubes. This can be done during normal operation at reduced load.

The auxiliary cooling system is a closed loop system. Plate and frame heat exchangers with circulating water as the cooling medium are provided. The system provides cooling water to the following systems:

1. Combustion turbine generator lube oil coolers
2. Combustion turbine generator air coolers
3. Steam turbine generator lube oil coolers
4. Steam turbine generator hydrogen coolers
5. Boiler feed water pumps
6. Air compressors

7. Generator seal oil coolers (as applicable)
8. Sample room chillers
9. Blowdown coolers
10. Condensate extraction pump-motor coolers

The CDR system in Case 14 requires a substantial amount of cooling water that is provided by the NGCC plant circulating water system. The additional cooling load imposed by the CDR is reflected in the significantly larger circulating water pumps and cooling tower in that case.

Buildings and Structures

Structures assumed for NGCC cases can be summarized as follows:

1. Generation Building housing the STG
2. Circulating Water Pump House
3. Administration / Office / Control Room / Maintenance Building
4. Water Treatment Building
5. Fire Water Pump House

5.1.8 ACCESSORY ELECTRIC PLANT

The accessory electric plant consists of all switchgear and control equipment, generator equipment, station service equipment, conduit and cable trays, wire, and cable. It also includes the main transformer, required foundations and standby equipment.

5.1.9 INSTRUMENTATION AND CONTROL

An integrated plant-wide DCS is provided. The DCS is a redundant microprocessor-based, functionally distributed system. The control room houses an array of video monitors and keyboard units. The monitor/keyboard units are the primary interface between the generating process and operations personnel. The DCS incorporates plant monitoring and control functions for all the major plant equipment. The DCS is designed to provide 99.5 percent availability.

The plant equipment and the DCS are designed for automatic response to load changes from minimum load to 100 percent. Startup and shutdown routines are implemented as supervised manual procedures with operator selection of modular automation routines available.

5.2 NGCC CASES

This section contains an evalution of plant designs for Cases 13 and 14. These two cases are similar in design and are based on an NGCC plant with a constant thermal input. Both plants use a single reheat 16.5 MPa/566°C/510°C (2400 psig/1050°F/950°F) cycle. The only difference between the two plants is that Case 14 includes CO_2 capture while Case 13 does not.

The balance of Section 5.2 is organized as follows:

- Process and System Description provides an overview of the technology operation as applied to Case 13. The systems that are common to all NGCC cases were covered in Section 5.1 and only features that are unique to Case 13 are discussed further in this section.
- Key Assumptions is a summary of study and modeling assumptions relavant to Cases 13 and 14.
- Sparing Philosophy is provided for both Cases 13 and 14.
- Performance Results provides the main modeling results from Case 13, including the performance summary, environmental performance, water balance, mass and energy balance diagrams and energy balance table.
- Equipment List provides an itemized list of major equipment for Case 13 with account codes that correspond to the cost accounts in the Cost Estimates section.
- Cost Estimates provides a summary of capital and operating costs for Case 13.
- Process and System Description, Performance Results, Equipment List and Cost Estimates are reported for Case 14.

5.2.1 PROCESS DESCRIPTION

In this section the NGCC process without CO_2 capture is described. The system description follows the block flow diagram (BFD) in Exhibit 5-3 and stream numbers reference the same Exhibit. The tables in Exhibit 5-4 provide process data for the numbered streams in the BFD. The BFD shows only one of the two combustion turbine/HRSG combinations, but the flow rates in the stream table are the total for two systems.

Ambient air (stream 1) and natural gas (stream 2) are combined in the dry LNB, which is operated to control the rotor inlet temperature at 1399°C (2550°F). The flue gas exits the turbine at 631°C (1167°F) (stream 3) and passes into the HRSG. The HRSG generates both the main steam and reheat steam for the steam turbine. Flue gas exits the HRSG at 104°C (220°F) and passes to the plant stack

Exhibit 5-3 Case 13 Process Flow Diagram, NGCC without CO_2 Capture

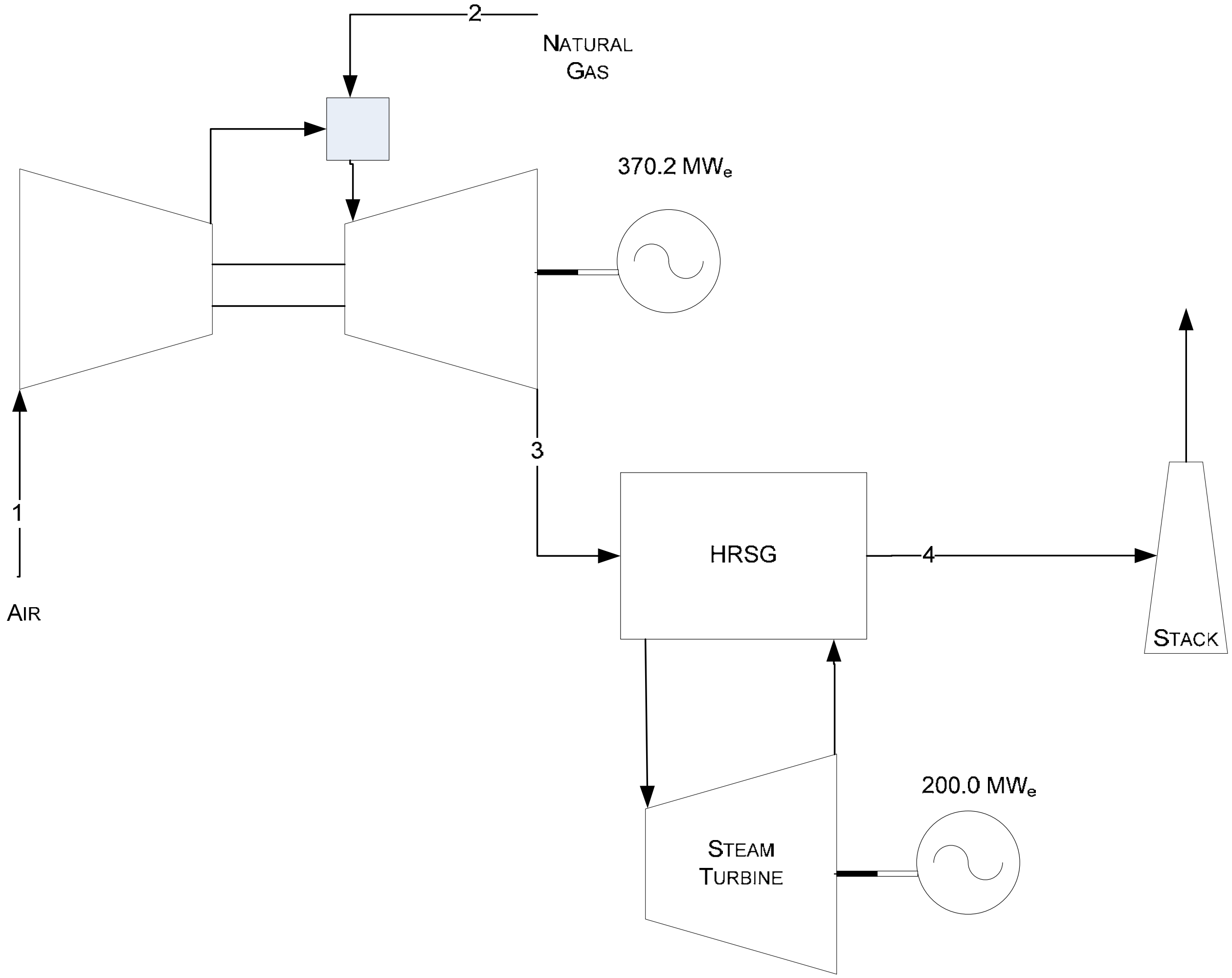


Exhibit 5-4 Case 13 Stream Table, NGCC without CO_2 Capture

	1	2	3	4
V-L Mole Fraction				
Ar	0.0092	0.0000	0.0089	0.0089
CH_4	0.0000	0.9390	0.0000	0.0000
C_2H_6	0.0000	0.0320	0.0000	0.0000
C_3H_8	0.0000	0.0070	0.0000	0.0000
C_4H_{10}	0.0000	0.0040	0.0000	0.0000
CO_2	0.0003	0.0100	0.0405	0.0405
H_2O	0.0099	0.0000	0.0869	0.0869
N_2	0.7732	0.0080	0.7430	0.7430
O_2	0.2074	0.0000	0.1207	0.1207
SO_2	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	120,220	4,793	250,304	250,304
V-L Flowrate (lb/hr)	3,469,190	82,591	7,103,560	7,103,560
Temperature (°F)	59	100	1,167	220
Pressure (psia)	14.7	450.0	15.2	15.2
Enthalpy (BTU/lb)[A]	13.1	34.4	360.5	106.6
Density (lb/ft^3)	0.076	1.291	0.025	0.059
Molecular Weight	28.857	17.232	28.380	28.380

A - Reference conditions are 32.02 F & 0.089 PSIA

5.2.2 KEY SYSTEM ASSUMPTIONS

System assumptions for Cases 13 and 14, NGCC with and without CO_2 capture, are compiled in Exhibit 5-5.

Exhibit 5-5 NGCC Plant Study Configuration Matrix

	Case 13 w/o CO_2 Capture	**Case 14 w/CO_2 Capture**
Steam Cycle, MPa/°C/°C (psig/°F/°F)	16.5/566/510 (2400/1050/950)	16.5/566/510 (2400/1050/950)
Fuel	Natural Gas	Natural Gas
Fuel Pressure at Plant Battery Limit MPa (psig)	3.1 (450)	3.1 (450)
Condenser Pressure, mm Hg (in Hg)	50.8 (2)	50.8 (2)
Cooling Water to Condenser, °C (ºF)	16 (60)	16 (60)
Cooling Water from Condenser, °C (ºF)	27 (80)	27 (80)
Stack Temperature, °C (°F)	104 (220)	29 (85)
SO_2 Control	Low Sulfur Fuel	Low Sulfur Fuel
NOx Control	LNB and SCR	LNB and SCR
SCR Efficiency, % (A)	90	90
Ammonia Slip (End of Catalyst Life), ppmv	10	10
Particulate Control	N/A	N/A
Mercury Control	N/A	N/A
CO_2 Control	N/A	Econamine FG Plus
CO_2 Capture, % (A)	N/A	90
CO_2 Sequestration	N/A	Off-site Saline Formation

A. Removal efficiencies are based on the flue gas content

Balance of Plant – Cases 13 and 14

The balance of plant assumptions are common to both NGCC cases and are presented in Exhibit 5-6.

Exhibit 5-6 NGCC Balance of Plant Assumptions

Cooling System	Recirculating Wet Cooling Tower
Fuel and Other Storage Natural Gas	Pipeline supply at 3.1 MPa (450 psia) and 38°C (100°F)
Ash	N/A
Gypsum	N/A
Limestone	N/A
Plant Distribution Voltage Motors below 1 hp	110/220 volt
Motors between 1 hp and 250 hp	480 volt
Motors between 250 hp and 5,000 hp	4,160 volt
Motors above 5,000 hp	13,800 volt
Steam and Gas Turbine generators	24,000 volt
Grid Interconnection voltage	345 kV
Water and Waste Water Makeup Water	The water supply is 50 percent from a local Publicly Owned Treatment Works (POTW) and 50 percent from groundwater, and is assumed to be in sufficient quantities to meet plant makeup requirements. Makeup for potable, process, and de-ionized (DI) water is drawn from municipal sources.
Process Wastewater	Storm water that contacts equipment surfaces is collected and treated for discharge through a permitted discharge.
Sanitary Waste Disposal	Design includes a packaged domestic sewage treatment plant with effluent discharged to the industrial wastewater treatment system. Sludge is hauled off site. Packaged plant is sized for 5.68 cubic meters per day (1,500 gallons per day)
Water Discharge	Most of the process wastewater is recycled to the cooling tower basin. Blowdown is treated for chloride and metals, and discharged.

5.2.3 SPARING PHILOSOPHY

Dual trains are used to accommodate the size of commercial gas turbines. There is no redundancy other than normal sparing of rotating equipment. The plant design consists of the following major subsystems:

- Two advanced F class combustion turbine generators (2 x 50%)
- Two 3-pressure reheat HRSGs with self supporting stacks and SCR systems (2 x 50%)
- One 3-pressure reheat, triple-admission steam turbine generator (1 x 100%)

- Two trains of Econamine FG Plus CO_2 capture (2 x 50%) (Case 14 only)

5.2.4 CASE 13 PERFORMANCE RESULTS

The plant produces a net output of 560 MW at a net plant efficiency of 50.8 percent (HHV basis).

Overall plant performance is summarized in Exhibit 5-7 which includes auxiliary power requirements.

Exhibit 5-7 Case 13 Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine Power	370,170
Steam Turbine Power	200,030
TOTAL POWER, kWe	**570,200**
AUXILIARY LOAD SUMMARY, kWe	
Condensate Pumps	130
Boiler Feedwater Pumps	2,970
Miscellaneous Balance of Plant (Note 1)	500
Gas Turbine Auxiliaries	700
Steam Turbine Auxiliaries	100
Amine System Auxiliaries	N/A
CO_2 Compression	N/A
Circulating Water Pumps	2,450
Cooling Tower Fans	1,260
Transformer Loss	1,730
TOTAL AUXILIARIES, kWe	**9,840**
NET POWER, kWe	**560,360**
Net Plant Efficiency (HHV)	50.8%
Net Plant Heat Rate (Btu/kWh)	6,719
CONDENSER COOLING DUTY, 10^6 kJ/h (10^6 Btu/h)	**1,162 (1,102)**
CONSUMABLES	
Natural Gas, kg/h (lb/h)	74,926 (165,182)
Thermal Input, kWt (HHV)	1,103,363
Raw Water Usage, m^3/min (gpm)	9.5 (2,512)

Notes:
1. Includes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

Environmental Performance

The environmental targets for emissions of NOx, SO_2 and particulate matter were presented in Section 2.4. A summary of the plant air emissions for Case 13 is presented in Exhibit 5-8.

Exhibit 5-8 Case 13 Air Emissions

	kg/GJ ($lb/10^6$ Btu)	Tonne/year (ton/year) 85% capacity factor	kg/MWh (lb/MWh)
SO_2	Negligible	Negligible	Negligible
NO_X	0.004 (0.009)	115 (127)	0.027 (0.060)
Particulates	Negligible	Negligible	Negligible
Hg	Negligible	Negligible	Negligible
CO_2	51 (119)	1,507,000 (1,662,000)	355 (783)
CO_2[1]			361 (797)

[1] CO_2 emissions based on net power instead of gross power

The operation of the modern, state-of-the-art gas turbine fueled by natural gas, coupled to a HRSG, results in very low levels of NOx emissions and negligible levels of SO_2, particulate and Hg emissions. As noted in Section 2.4, if the fuel contains the maximum amount of sulfur compounds allowed in pipeline natural gas, the NGCC SO_2 emissions would be 21 tonnes/yr (23 tons/yr) at 85 percent capacity factor, or 0.00195 lb/MMBtu.

The low level of NOx production (2.5 ppmvd at 15 percent O_2) is achieved by utilizing a dry LNB coupled with an SCR system.

CO_2 emissions are reduced relative to those produced by burning coal given the same power output because of the higher heat content of natural gas, the lower carbon intensity of gas relative to coal, and the higher overall efficiency of the NGCC plant relative to a coal-fired plant.

Exhibit 5-9 shows the overall water balance for the plant. Raw water is obtained from groundwater (50 percent) and from municipal sources (50 percent). The water usage represents only the contribution of raw water makeup. In some cases the water demand is greater than raw water makeup because of internal water recycle streams. For example, the boiler feedwater blowdown stream is re-used as makeup to the cooling tower, thus reducing the raw water requirement by that amount.

Exhibit 5-9 Case 13 Water Balance

Water Use	Water Demand, m^3/min (gpm)	Internal Recycle, m^3/min (gpm)	Raw Water Makeup, m^3/min (gpm)
BFW Makeup	0.1 (23)	0	0.1 (23)
Cooling Tower Makeup	9.5 (2,511)	0.1 (23)	9.4 (2,488)
Total	**9.6 (2,534)**	**0.1 (23)**	**9.5 (2,511)**

Heat and Mass Balance Diagrams

A heat and mass balance diagram is shown for the NGCC in Exhibit 5-10.

An overall plant energy balance is provided in tabular form in Exhibit 5-11. The power out is the combined combustion turbine and steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 5-7) is calculated by multiplying the power out by a combined generator efficiency of 98.4 percent.

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Exhibit 5-10 Case 13 Heat and Mass Balance, NGCC without CO_2 Capture

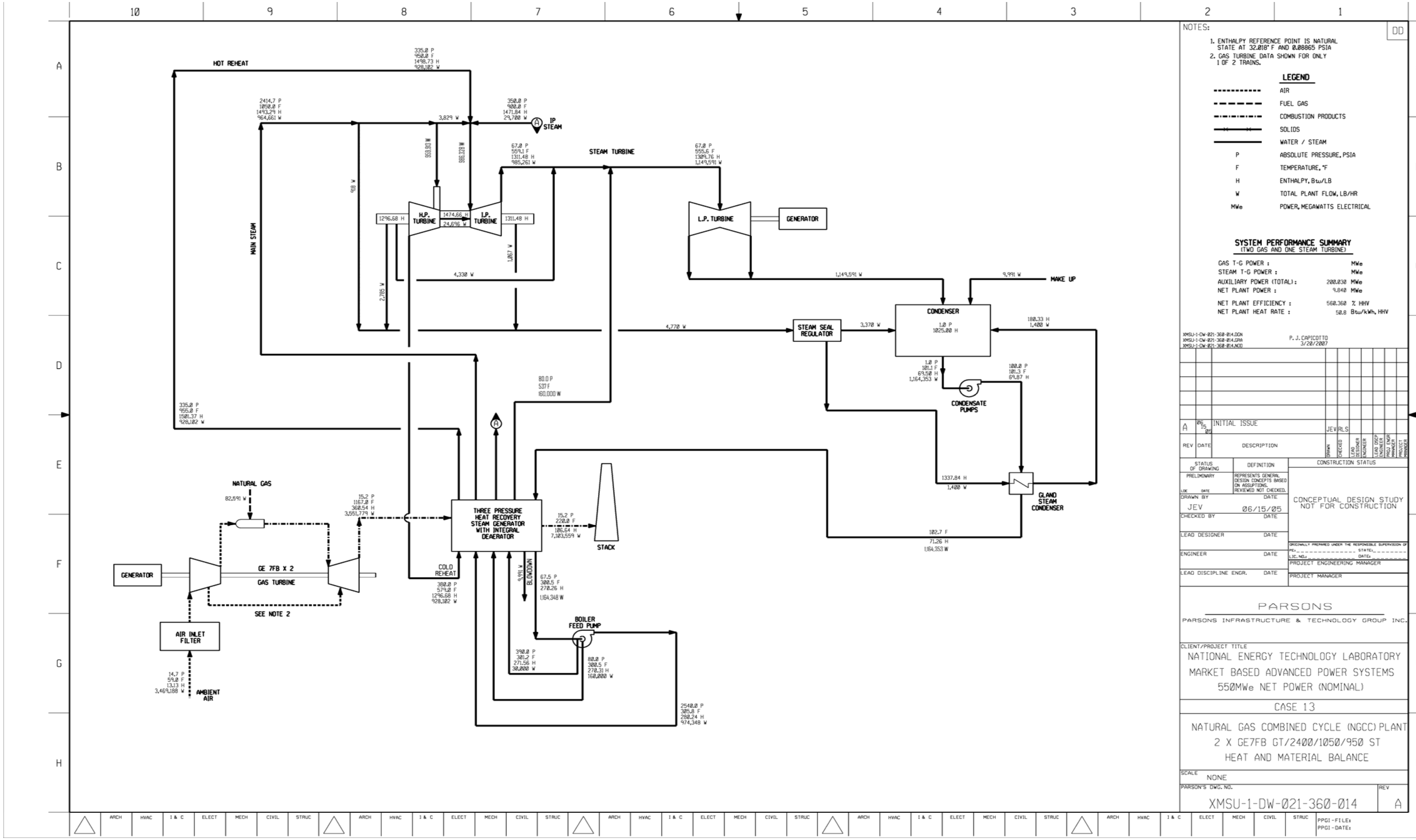

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Exhibit 5-11 Case 13 Overall Energy Balance (0°C [32°F] Reference)

	HHV	Sensible + Latent	Power	Total
Heat In (MMBtu/hr)				
Natural Gas	3,764.8	5.7		3,770.5
Ambient Air		91.1		91.1
Water		0.3		0.3
Auxiliary Power			33.6	33.6
Totals	**3,764.8**	**97.1**	**33.6**	**3,895.5**
Heat Out (MMBtu/hr)				
Flue Gas Exhaust		757.5		757.5
Condenser		1,102.0		1,102.0
Process Losses (1)		58.7		58.7
Power			1,977.3	1,977.3
Totals	**0.0**	**1,918.2**	**1,977.3**	**3,895.5**

(1) Process Losses are calculated by difference and reflect various boiler, turbine, and other heat and work losses. Aspen flowsheet balance is within 0.5 percent.

5.2.5 CASE 13 – MAJOR EQUIPMENT LIST

Major equipment items for the NGCC plant with no CO_2 capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 5.2.6. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

ACCOUNT 1 COAL AND SORBENT HANDLING

N/A

ACCOUNT 2 FUEL AND SORBENT PREPARATION AND FEED

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	56 m3/min @ 3.1 MPa (1,991 acfm @ 450 psia) 41 cm (16 in) standard wall pipe	16 km (10 mile)	0
2	Gas Metering Station	--	56 m3/min (1,991 acfm)	1	0

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	696,521 liters (184,000 gal)	2	0
2	Condensate Pumps	Vertical canned	4,883 lpm @ 85 m H2O (1,290 gpm @ 280 ft H2O)	2	1
3	Boiler Feedwater Pump	Horizontal, split case, multi-stage, centrifugal, with interstage bleed for IP and LP feedwater	HP water: 4,088 lpm @ 2,103 m H2O (1,080 gpm @ 6,900 ft H2O) IP water: 114 lpm @ 274 m H2O (30 gpm @ 900 ft H2O) LP water: 681 lpm @ 9.1 m H2O (180 gpm @ 30 ft H2O)	2	1
4	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/h, 2.8 MPa, 343°C (40,000 lb/h, 400 psig, 650°F)	1	0
5	Service Air Compressors	Flooded Screw	13 m3/min @ 0.7 MPa (450 scfm @ 100 psig)	2	1
6	Instrument Air Dryers	Duplex, regenerative	13 m3/min (450 scfm)	2	1
7	Closed Cycle Cooling Heat Exchangers	Plate and frame	40 MMkJ/hr (38 MMBtu/hr)	2	0
8	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	15,520 lpm @ 21 m H2O (4,100 gpm @ 70 ft H2O)	2	1
9	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 107 m H2O (1,000 gpm @ 350 ft H2O)	1	1
10	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 76 m H2O (700 gpm @ 250 ft H2O)	1	1
11	Raw Water Pumps	Stainless steel, single suction	5,300 lpm @ 18 m H2O (1,400 gpm @ 60 ft H2O)	2	1
12	Filtered Water Pumps	Stainless steel, single suction	151 lpm @ 49 m H2O (40 gpm @ 160 ft H2O)	2	1
13	Filtered Water Tank	Vertical, cylindrical	143,847 liter (38,000 gal)	1	0
14	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly and electro-deionization unit	341 lpm (90 gpm)	1	0
15	Liquid Waste Treatment System		10 years, 24-hour storm	1	0

ACCOUNT 4 GASIFIER, BOILER AND ACCESSORIES

N/A

ACCOUNT 5 FLUE GAS CLEANUP

N/A

ACCOUNT 6 COMBUSTION TURBINE GENERATORS AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gas Turbine	Advanced F class w/ dry low-NOx burner	185 MW	2	0
2	Gas Turbine Generator	TEWAC	210 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	2	0

ACCOUNT 7 WASTE HEAT BOILER, DUCTING, AND STACK

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	CS plate, type 409SS liner	46 m (150 ft) high x 5.2 m (17 ft) diameter	2	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	Main steam - 240,660 kg/h, 16.5 MPa/566°C (530,564 lb/h, 2,400 psig/1,050°F) Reheat steam - 231,539 kg/h, 2.3 MPa/510°C (510,456 lb/h, 335 psig/950°F)	2	0
3	SCR Reactor	Space for spare layer	1,773,548 kg/h (3,910,000 lb/h)	2	0
4	SCR Catalyst	--	Space available for an additional catalyst layer	1 layer	0
5	Dilution Air Blowers	Centrifugal	21 m3/min @ 91 cm WG (750 scfm @ 36 in WG)	2	1
6	Ammonia Feed Pump	Centrifugal	3.8 lpm @ 82 m H2O (1 gpm @ 270 ft H2O)	2	1
7	Ammonia Storage Tank	Horizontal tank	87,065 liter (23,000 gal)	1	0

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Tandem compound, HP, IP, and two-flow LP turbines	211 MW 16.5 MPa/566°C/510°C (2400 psig/ 1050°F/950°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	230 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Steam Bypass	One per HRSG	50% steam flow @ design steam conditions	2	0
4	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,276 MMkJ/hr, (1,210 MMBtu/hr), Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1	0

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	246,054 lpm @ 30.5 m (65,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT 1,365 MMkJ/hr (1,295 MMBtu/hr) heat load	1	0

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

N/A

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	24 kV/345 kV, 210 MVA, 3-ph, 60 Hz	2	0
2	STG Transformer	Oil-filled	24 kV/345 kV, 220 MVA, 3-ph, 60 Hz	1	0
3	Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 09 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 1 MVA, 3-ph, 60 Hz	1	1
5	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	2	0
6	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
7	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
8	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
9	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

ACCOUNT 12 INSTRUMENTATION AND CONTROL

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

5.2.6 CASE 13 – COST ESTIMATING

The cost estimating methodology was described previously in Section 2.6. Exhibit 5-12 shows the total plant capital cost summary organized by cost account and Exhibit 5-13 shows a more detailed breakdown of the capital costs. Exhibit 5-14 shows the initial and annual O&M costs.

The estimated TPC of the NGCC with no CO_2 capture is $554/kW. No process contingency was included in this case because all elements of the technology are commercially proven. The project contingency is 10.7 percent of TPC. The 20-year LCOE is 68.4 mills/kWh.

Exhibit 5-12 Case 13 Total Plant Cost Summary

Client:	USDOE/NETL		Report Date:	10-May-07
Project:	Bituminous Baseline Study			
	TOTAL PLANT COST SUMMARY			
Case:	Case 13 - NGCC w/o CO2			
Plant Size:	560.4 MW,net	Estimate Type: Conceptual	Cost Base (Dec)	2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2	COAL & SORBENT PREP & FEED	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	FEEDWATER & MISC. BOP SYSTEMS	$21,803	$4,553	$6,567	$0	$0	$32,923	$2,758	$0	$5,693	$41,374	$74
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.2	Syngas Cooling	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.3	ASU/Oxidant Compression	$0	$0	w/equip.	$0	$0	$0	$0	$0	$0	$0	$0
4.4-4.9	Other Gasification Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 4	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
5	Gas Cleanup & Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5B	CO_2 REMOVAL & COMPRESSION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$72,000	$0	$4,588	$0	$0	$76,589	$6,456	$0	$8,304	$91,349	$163
6.2-6.9	Combustion Turbine Other	$0	$681	$709	$0	$0	$1,390	$116	$0	$301	$1,807	$3
	SUBTOTAL 6	**$72,000**	**$681**	**$5,298**	**$0**	**$0**	**$77,979**	**$6,571**	**$0**	**$8,606**	**$93,156**	**$166**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$32,000	$0	$4,200	$0	$0	$36,200	$3,060	$0	$3,926	$43,186	$77
7.2-7.9	SCR System, Ductwork and Stack	$1,177	$881	$1,044	$0	$0	$3,101	$263	$0	$544	$3,908	$7
	SUBTOTAL 7	**$33,177**	**$881**	**$5,244**	**$0**	**$0**	**$39,301**	**$3,323**	**$0**	**$4,470**	**$47,094**	**$84**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$22,464	$0	$3,675	$0	$0	$26,139	$2,244	$0	$2,838	$31,222	$56
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$8,415	$755	$5,340	$0	$0	$14,511	$1,171	$0	$2,151	$17,834	$32
	SUBTOTAL 8	**$30,880**	**$755**	**$9,016**	**$0**	**$0**	**$40,651**	**$3,415**	**$0**	**$4,989**	**$49,055**	**$88**
9	COOLING WATER SYSTEM	$5,474	$4,330	$3,883	$0	$0	$13,686	$1,128	$0	$2,107	$16,921	$30
10	ASH/SPENT SORBENT HANDLING SYS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11	ACCESSORY ELECTRIC PLANT	$15,227	$3,466	$7,567	$0	$0	$26,261	$1,986	$0	$3,074	$31,321	$56
12	INSTRUMENTATION & CONTROL	$5,308	$555	$4,596	$0	$0	$10,459	$884	$0	$1,301	$12,643	$23
13	IMPROVEMENTS TO SITE	$1,635	$888	$4,384	$0	$0	$6,907	$608	$0	$1,503	$9,017	$16
14	BUILDINGS & STRUCTURES	$0	$3,920	$4,225	$0	$0	$8,145	$661	$0	$1,321	$10,127	$18
	TOTAL COST	**$185,504**	**$20,029**	**$50,779**	**$0**	**$0**	**$256,312**	**$21,334**	**$0**	**$33,064**	**$310,710**	**$554**

Exhibit 5-13 Case 13 Total Plant Cost Details

Client:	USDOE/NETL	**Report Date:**	10-May-07
Project:	Bituminous Baseline Study		

TOTAL PLANT COST SUMMARY

Case:	Case 13 - NGCC w/o CO2					
Plant Size:	560.4 MW,net	**Estimate Type:**	Conceptual	**Cost Base (Dec)**	2006	($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.2	Coal Stackout & Reclaim	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.3	Coal Conveyors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.4	Other Coal Handling	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.5	Sorbent Receive & Unload	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.6	Sorbent Stackout & Reclaim	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.7	Sorbent Conveyors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.8	Other Sorbent Handling	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.9	Coal & Sorbent Hnd.Foundations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 1.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying incl w/2.3	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.2	Prepared Coal Storage & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.3	Slurry Prep & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.4	Misc.Coal Prep & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.5	Sorbent Prep Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.6	Sorbent Storage & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.7	Sorbent Injection System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.8	Booster Air Supply System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.9	Coal & Sorbent Feed Foundation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 2.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	$2,501	$2,609	$2,147	$0	$0	$7,256	$597	$0	$1,178	$9,030	$16
3.2	Water Makeup & Pretreating	$1,459	$152	$761	$0	$0	$2,373	$201	$0	$515	$3,088	$6
3.3	Other Feedwater Subsystems	$1,151	$390	$328	$0	$0	$1,869	$150	$0	$303	$2,321	$4
3.4	Service Water Systems	$174	$355	$1,151	$0	$0	$1,679	$145	$0	$365	$2,190	$4
3.5	Other Boiler Plant Systems	$1,167	$448	$1,037	$0	$0	$2,652	$222	$0	$431	$3,305	$6
3.6	FO Supply Sys & Nat Gas	$13,960	$483	$421	$0	$0	$14,864	$1,251	$0	$2,417	$18,533	$33
3.7	Waste Treatment Equipment	$524	$0	$300	$0	$0	$824	$71	$0	$179	$1,074	$2
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	$869	$117	$421	$0	$0	$1,406	$121	$0	$306	$1,833	$3
	SUBTOTAL 3.	**$21,803**	**$4,553**	**$6,567**	**$0**	**$0**	**$32,923**	**$2,758**	**$0**	**$5,693**	**$41,374**	**$74**
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries (E-GAS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.2	Syngas Cooling (w/ 4.1	w/4.1	$0	w/4.1	w/4.1	$0	$0	$0	$0	$0	$0	$0
4.3	ASU/Oxidant Compression	$0	$0	w/equip.	$0	$0	$0	$0	$0	$0	$0	$0
4.4	LT Heat Recovery & FG Saturation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.5	Misc. Gasification Equipment	w/4.1&4.2	$0	w/4.1&4.2	$0	$0	$0	$0	$0	$0	$0	$0
4.6	Other Gasification Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.8	Major Component Rigging		$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.9	Gasification Foundations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 4.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**

Exhibit 5-13 Case 13 Total Plant Cost Details (Continued)

Client: USDOE/NETL — **Report Date:** 10-May-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 13 - NGCC w/o CO2
Plant Size: 560.4 MW,net — **Estimate Type:** Conceptual — **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5A	GAS CLEANUP & PIPING											
5A.1	Double Stage Selexol	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.2	Elemental Sulfur Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.3	Mercury Removal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.4	Shift Reactors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.6	Blowback Gas Systems	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.7	Fuel Gas Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.9	HGCU Foundations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 5.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
5B	CO2 REMOVAL & COMPRESSION											
5B.1	CO2 Removal System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5B.2	CO2 Compression & Drying	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 5.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$72,000	$0	$4,588	$0	$0	$76,589	$6,456	$0	$8,304	$91,349	$163
6.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.3	Compressed Air Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.9	Combustion Turbine Foundations	$0	$681	$709	$0	$0	$1,390	$116	$0	$301	$1,807	$3
	SUBTOTAL 6.	**$72,000**	**$681**	**$5,298**	**$0**	**$0**	**$77,979**	**$6,571**	**$0**	**$8,606**	**$93,156**	**$166**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$32,000	$0	$4,200	$0	$0	$36,200	$3,060	$0	$3,926	$43,186	$77
7.2	SCR System	$1,177	$494	$694	$0	$0	$2,365	$202	$0	$385	$2,952	$5
7.3	Ductwork	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.4	Stack	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.9	HRSG,Duct & Stack Foundations	$0	$386	$349	$0	$0	$736	$61	$0	$159	$956	$2
	SUBTOTAL 7.	**$33,177**	**$881**	**$5,244**	**$0**	**$0**	**$39,301**	**$3,323**	**$0**	**$4,470**	**$47,094**	**$84**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$22,464	$0	$3,675	$0	$0	$26,139	$2,244	$0	$2,838	$31,222	$56
8.2	Turbine Plant Auxiliaries	$153	$0	$352	$0	$0	$505	$44	$0	$55	$604	$1
8.3	Condenser & Auxiliaries	$4,112	$0	$1,053	$0	$0	$5,165	$439	$0	$560	$6,164	$11
8.4	Steam Piping	$4,150	$0	$2,733	$0	$0	$6,884	$524	$0	$1,111	$8,519	$15
8.9	TG Foundations	$0	$755	$1,202	$0	$0	$1,957	$165	$0	$424	$2,547	$5
	SUBTOTAL 8.	**$30,880**	**$755**	**$9,016**	**$0**	**$0**	**$40,651**	**$3,415**	**$0**	**$4,989**	**$49,055**	**$88**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$3,850	$0	$525	$0	$0	$4,375	$370	$0	$474	$5,219	$9
9.2	Circulating Water Pumps	$1,122	$0	$67	$0	$0	$1,189	$91	$0	$128	$1,409	$3
9.3	Circ.Water System Auxiliaries	$93	$0	$12	$0	$0	$105	$9	$0	$11	$125	$0
9.4	Circ.Water Piping	$0	$2,752	$656	$0	$0	$3,409	$270	$0	$552	$4,230	$8
9.5	Make-up Water System	$228	$0	$302	$0	$0	$529	$45	$0	$86	$661	$1
9.6	Component Cooling Water Sys	$181	$217	$143	$0	$0	$541	$45	$0	$88	$674	$1
9.9	Circ.Water System Foundations& Structures	$0	$1,361	$2,177	$0	$0	$3,538	$298	$0	$767	$4,603	$8
	SUBTOTAL 9.	**$5,474**	**$4,330**	**$3,883**	**$0**	**$0**	**$13,686**	**$1,128**	**$0**	**$2,107**	**$16,921**	**$30**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Slag Dewatering & Cooling	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0
10.2	Gasifier Ash Depressurization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.3	Cleanup Ash Depressurization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.4	High Temperature Ash Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.5	Other Ash Rrecovery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.7	Ash Transport & Feed Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.8	Misc. Ash Handling Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.9	Ash/Spent Sorbent Foundation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 10.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**

Exhibit 5-13 Case 13 Total Plant Cost Details (Continued)

Client: USDOE/NETL **Report Date:** 10-May-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 13 - NGCC w/o CO2
Plant Size: 560.4 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$2,320	$0	$1,405	$0	$0	$3,724	$314	$0	$303	$4,342	$8
11.2	Station Service Equipment	$1,115	$0	$98	$0	$0	$1,213	$103	$0	$99	$1,415	$3
11.3	Switchgear & Motor Control	$1,421	$0	$243	$0	$0	$1,664	$138	$0	$180	$1,983	$4
11.4	Conduit & Cable Tray	$0	$695	$2,110	$0	$0	$2,805	$240	$0	$457	$3,502	$6
11.5	Wire & Cable	$0	$2,128	$1,338	$0	$0	$3,467	$225	$0	$554	$4,245	$8
11.6	Protective Equipment	$0	$519	$1,838	$0	$0	$2,356	$206	$0	$256	$2,819	$5
11.7	Standby Equipment	$95	$0	$90	$0	$0	$185	$16	$0	$20	$221	$0
11.8	Main Power Transformers	$10,277	$0	$140	$0	$0	$10,416	$707	$0	$1,112	$12,236	$22
11.9	Electrical Foundations	$0	$124	$306	$0	$0	$430	$37	$0	$93	$560	$1
	SUBTOTAL 11.	**$15,227**	**$3,466**	**$7,567**	**$0**	**$0**	**$26,261**	**$1,986**	**$0**	**$3,074**	**$31,321**	**$56**
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
12.3	Steam Turbine Control	w/8.1	$0	w/8.1	$0	$0	$0	$0	$0	$0	$0	$0
12.4	Other Major Component Control	$675	$0	$439	$0	$0	$1,114	$96	$0	$181	$1,391	$2
12.5	Signal Processing Equipment	W/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.6	Control Boards,Panels & Racks	$202	$0	$126	$0	$0	$328	$28	$0	$53	$409	$1
12.7	Computer & Accessories	$3,228	$0	$101	$0	$0	$3,329	$283	$0	$361	$3,973	$7
12.8	Instrument Wiring & Tubing	$0	$555	$1,085	$0	$0	$1,640	$124	$0	$265	$2,028	$4
12.9	Other I & C Equipment	$1,203	$0	$2,845	$0	$0	$4,049	$353	$0	$440	$4,842	$9
	SUBTOTAL 12.	**$5,308**	**$555**	**$4,596**	**$0**	**$0**	**$10,459**	**$884**	**$0**	**$1,301**	**$12,643**	**$23**
13	Improvements to Site											
13.1	Site Preparation	$0	$87	$1,757	$0	$0	$1,845	$163	$0	$401	$2,409	$4
13.2	Site Improvements	$0	$801	$1,002	$0	$0	$1,803	$159	$0	$392	$2,353	$4
13.3	Site Facilities	$1,635	$0	$1,624	$0	$0	$3,259	$287	$0	$709	$4,255	$8
	SUBTOTAL 13.	**$1,635**	**$888**	**$4,384**	**$0**	**$0**	**$6,907**	**$608**	**$0**	**$1,503**	**$9,017**	**$16**
14	Buildings & Structures											
14.1	Combustion Turbine Area	$0	$212	$113	$0	$0	$325	$26	$0	$53	$403	$1
14.2	Steam Turbine Building	$0	$1,855	$2,503	$0	$0	$4,357	$357	$0	$707	$5,422	$10
14.3	Administration Building	$0	$429	$294	$0	$0	$723	$57	$0	$117	$898	$2
14.4	Circulation Water Pumphouse	$0	$143	$72	$0	$0	$215	$17	$0	$35	$267	$0
14.5	Water Treatment Buildings	$0	$317	$293	$0	$0	$610	$49	$0	$99	$758	$1
14.6	Machine Shop	$0	$372	$241	$0	$0	$613	$49	$0	$99	$761	$1
14.7	Warehouse	$0	$240	$147	$0	$0	$387	$31	$0	$63	$480	$1
14.8	Other Buildings & Structures	$0	$72	$53	$0	$0	$125	$10	$0	$20	$155	$0
14.9	Waste Treating Building & Str.	$0	$281	$509	$0	$0	$791	$66	$0	$128	$985	$2
	SUBTOTAL 14.	**$0**	**$3,920**	**$4,225**	**$0**	**$0**	**$8,145**	**$661**	**$0**	**$1,321**	**$10,127**	**$18**
	TOTAL COST	**$185,504**	**$20,029**	**$50,779**	**$0**	**$0**	**$256,312**	**$21,334**	**$0**	**$33,064**	**$310,710**	**$554**

Exhibit 5-14 Case 13 Initial and Annual Operating and Maintenance Cost Summary

INITIAL & ANNUAL O&M EXPENSES					Cost Base (Dec)	2006
Case 13 - NGCC w/o CO2					Heat Rate-net(Btu/kWh):	6,719
					MWe-net:	560
					Capacity Factor: (%):	85
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate(base):	33.00 $/hour					
Operating Labor Burden:	30.00 % of base					
Labor O-H Charge Rate:	25.00 % of labor					
			Total			
Skilled Operator	1.0		1.0			
Operator	2.0		2.0			
Foreman	1.0		1.0			
Lab Tech's, etc.	1.0		1.0			
TOTAL-O.J.'s	5.0		5.0			
					Annual Cost $	Annual Unit Cost $/kW-net
Annual Operating Labor Cost					$1,879,020	$3.353
Maintenance Labor Cost					$2,521,575	$4.500
Administrative & Support Labor					$1,100,149	$1.963
TOTAL FIXED OPERATING COSTS					**$5,500,743**	**$9.816**
VARIABLE OPERATING COSTS						
						$/kWh-net
Maintenance Material Cost					**$3,782,362**	**$0.00091**
Consumables	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost		
Water(/1000 gallons)	0	1,808	1.03	**$0**	**$577,734**	**$0.00014**
Chemicals						
MU & WT Chem.(lb)	75,397	10,771	0.16	$12,425	$550,716	$0.00013
Carbon (Mercury Removal) (lb.)	0	0	1.00	$0	$0	$0.00000
COS Catalyst (lb)	0	0	0.60	$0	$0	$0.00000
MEA Solvent (ton)	0	0	2,142.40	$0	$0	$0.00000
Activated Carbon(lb)	0	0	1.00	$0	$0	$0.00000
Corrosion Inhibitor	0	0	0.00	$0	$0	$0.00000
SCR Catalyst (m3)	w/equip.	0.08	5,500.00	$0	$140,093	$0.00003
Ammonia (28% NH3) ton	55	8	190.00	$10,438	$462,620	$0.00011
Subtotal Chemicals				**$22,863**	**$1,153,429**	**$0.00028**
Other						
Supplemental Fuel(MBtu)	0	0	0.00	$0	$0	$0.00000
Gases,N2 etc.(/100scf)	0	0	0.00	$0	$0	$0.00000
L.P. Steam(/1000 pounds)	0	0	0.00	$0	$0	$0.00000
Subtotal Other				**$0**	**$0**	**$0.00000**
Waste Disposal						
Spent Mercury Catalyst (lb.)	0	0	0.00	$0	$0	$0.00000
Flyash (ton)	0	0	0.00	$0	$0	$0.00000
Bottom Ash(ton)	0	0	0.00	$0	$0	$0.00000
Subtotal-Waste Disposal				**$0**	**$0**	**$0.00000**
By-products & Emissions						
Sulfur(tons)	0	0	0.00	$0	$0	$0.00000
Subtotal By-Products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$22,863**	**$5,513,526**	**$0.00132**
Fuel(MMBtu)	2,710,842	90,361	6.75	**$18,298,186**	**$189,233,740**	**$0.04535**

5.2.7 CASE 14 – NGCC WITH CO_2 CAPTURE

The plant configuration for Case 14 is the same as Case 13 with the exception that the Econamine FG Plus CDR technology was added for CO_2 capture. The nominal net output decreases to 482 MW because, like the IGCC cases, the combustion turbine fixes the output and the CDR facility significantly increases the auxiliary power load.

The process description for Case 14 is essentially the same as Case 13 with one notable exception, the addition of CO_2 capture. A BFD and stream tables for Case 14 are shown in Exhibit 5-15 and Exhibit 5-16, respectively. Since the CDR facility process description was provided in Section 4.1.7, it is not repeated here.

5.2.8 CASE 14 PERFORMANCE RESULTS

The Case 14 modeling assumptions were presented previously in Section 5.2.2.

The plant produces a net output of 482 MW at a net plant efficiency of 43.7 percent (HHV basis). Overall plant performance is summarized in Exhibit 5-17 which includes auxiliary power requirements. The CDR facility, including CO_2 compression, accounts for over 64 percent of the auxiliary plant load. The circulating water system (circulating water pumps and cooling tower fan) accounts for nearly 20 percent of the auxiliary load, largely due to the high cooling water demand of the CDR facility.

Exhibit 5-15 Case 14 Process Flow Diagram, NGCC with CO_2 Capture

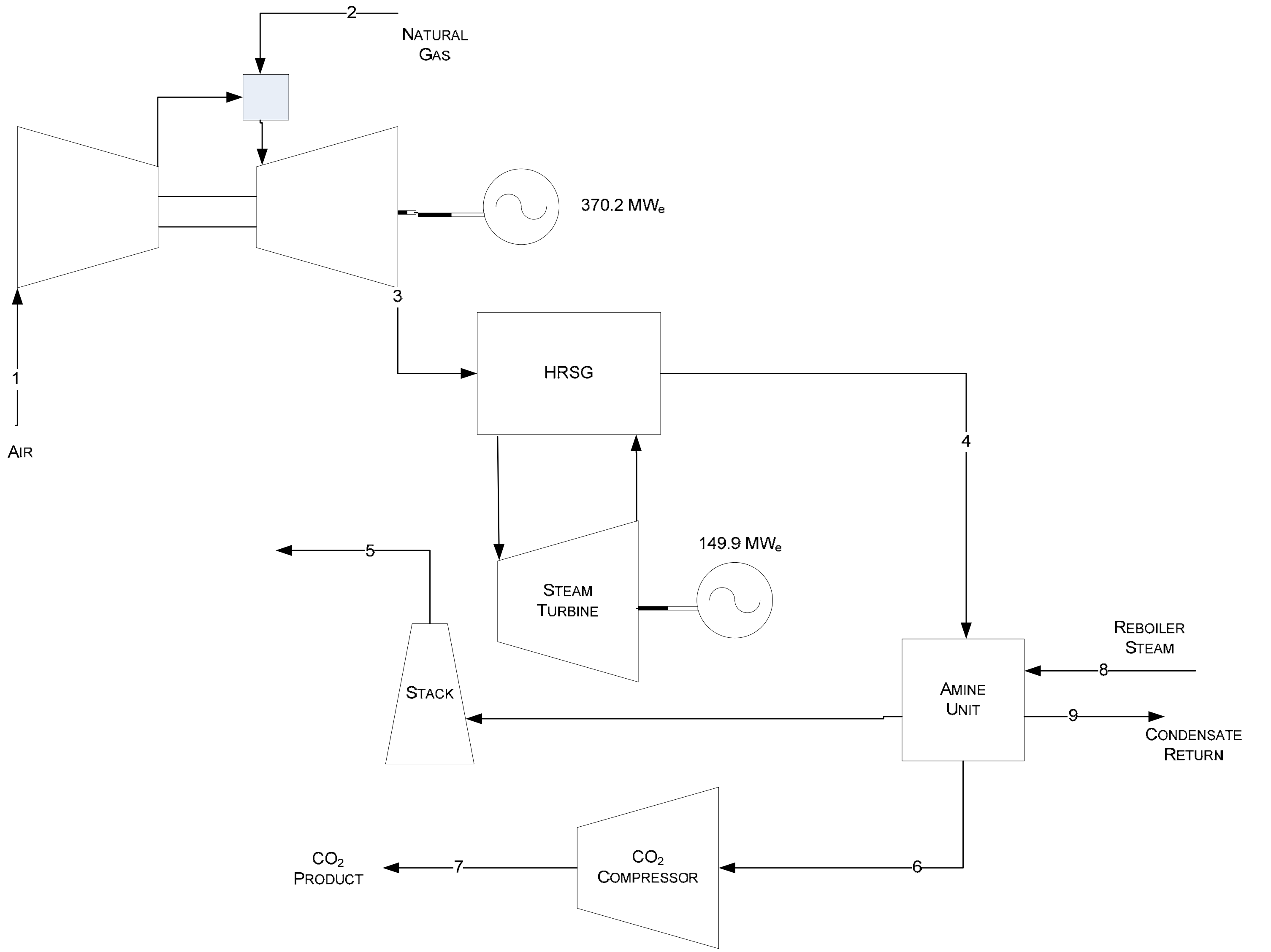

Exhibit 5-16 - Case 14 Stream Table, NGCC with CO_2 Capture

	1	2	3	4	5	6	7	8	9
V-L Mole Fraction									
Ar	0.0092	0.0000	0.0089	0.0089	0.0098	0.0000	0.0000	0.0000	0.0000
CH_4	0.0000	0.9390	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_2H_6	0.0000	0.0320	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_3H_8	0.0000	0.0070	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_4H_{10}	0.0000	0.0040	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0003	0.0100	0.0405	0.0405	0.0045	0.9767	1.0000	0.0000	0.0000
H_2O	0.0099	0.0000	0.0869	0.0869	0.0339	0.0233	0.0000	1.0000	1.0000
N_2	0.7732	0.0080	0.7430	0.7430	0.8188	0.0000	0.0000	0.0000	0.0000
O_2	0.2074	0.0000	0.1207	0.1207	0.1330	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	120,220	4,793	125,152	250,304	227,129	9,347	9,130	34,122	34,122
V-L Flowrate (lb/hr)	3,469,190	82,591	3,551,780	7,103,560	6,448,730	405,714	401,794	614,710	614,710
Temperature (°F)	59	100	1,167	283	85	69	124	555	300
Pressure (psia)	14.7	450.0	15.2	15.2	14.7	23.5	2,214.7	67.5	67.5
Enthalpy (BTU/lb)[A]	13.1	34.4	360.5	122.6	36.1	11.2	-70.8	1309.6	270.3
Density (lb/ft^3)	0.08	1.29	0.02	0.05	0.07	0.18	40.75	0.11	57.28
Molecular Weight	28.86	17.23	28.38	28.38	28.39	43.40	44.01	18.02	18.02

A - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 5-17 Case 14 Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine Power	370,170
Steam Turbine Power	149,920
TOTAL POWER, kWe	**520,090**
AUXILIARY LOAD SUMMARY, kWe	
Condensate Pumps	60
Boiler Feedwater Pumps	2,920
Miscellaneous Balance of Plant (Note 1)	500
Gas Turbine Auxiliaries	700
Steam Turbine Auxiliaries	100
Amine System Auxiliaries	9,580
CO_2 Compression	15,040
Circulating Water Pumps	5,040
Cooling Tower Fans	2,600
Transformer Loss	1,660
TOTAL AUXILIARIES, kWe	**38,200**
NET POWER, kWe	**481,890**
Net Plant Efficiency (HHV)	43.7%
Net Plant Heat Rate (Btu/kWh)	7,813
CONDENSER COOLING DUTY, 10^6 kJ/h (10^6 Btu/h)	**550 (522)**
CONSUMABLES	
Natural Gas kg/h (lb/h)	74,926 (165,182)
Thermal Input, kWt (HHV)	1,103,363
Raw Water Usage, m^3/min (gpm)	17.7 (4,680)

Notes:

1. Includes plant control systems, lighting, HVAC and miscellaneous low voltage loads

Environmental Performance

The environmental targets for emissions of NOx, SO_2 and particulate matter were presented in Section 2.4. A summary of the plant air emissions for Case 14 is presented in Exhibit 5-18.

Exhibit 5-18 Case 14 Air Emissions

	kg/GJ (lb/10^6 Btu)	Tonne/year (ton/year) 85% capacity factor	kg/MWh (lb/MWh)
SO_2	Negligible	Negligible	Negligible
NO_X	0.004 (0.009)	115 (127)	0.030 (0.066)
Particulates	Negligible	Negligible	Negligible
Hg	Negligible	Negligible	Negligible
CO_2	5.1 (12)	151,000 (166,000)	39 (86)
CO_2[1]			42 (93)

[1] CO_2 emissions based on net power instead of gross power

The operation of the modern, state-of-the-art gas turbine fueled by natural gas, coupled to a HRSG, results in very low levels of NOx emissions and negligible levels of SO_2, particulate and Hg emissions. As noted in Section 2.4, if the fuel contains the maximum amount of sulfur compounds allowed in pipeline natural gas, the NGCC SO_2 emissions would be 21 tonnes/yr (23 tons/yr) at 85 percent capacity factor, or 0.00195 lb/MMBtu.

The low level of NOx production (2.5 ppmvd at 15 percent O_2) is achieved by utilizing a dry LNB coupled with an SCR system.

Ninety percent of the CO_2 in the flue gas is removed in CDR facility.

Exhibit 5-19 shows the overall water balance for the plant. Raw water is obtained from groundwater (50 percent) and from municipal sources (50 percent). The water usage represents only the contribution of raw water makeup. In some cases the water demand is greater than raw water makeup because of internal water recycle streams. For example, the boiler feedwater blowdown stream and condensate recovered from the flue gas prior to the CO_2 absorber are re-used as makeup to the cooling tower, thus reducing the raw water requirement by that amount.

Exhibit 5-19 Case 14 Water Balance

Water Use	Water Demand, m^3/min (gpm)	Internal Recycle, m^3/min (gpm)	Raw Water Makeup, m^3/min (gpm)
BFW Makeup	0.1 (23)	0	0.1 (23)
Cooling Tower Makeup	16.6 (4,395)	2.0 (518)	14.7 (3,877)
Total	**16.7 (4,418)**	**2.0 (518)**	**14.8 (3,900)**

Heat and Mass Balance Diagrams

A heat and mass balance diagram is shown for the NGCC in Exhibit 5-20.

An overall plant energy balance is provided in tabular form in Exhibit 5-21. The power out is the combined combustion turbine and steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 5-17) is calculated by multiplying the power out by a combined generator efficiency of 98.3 percent. The Econamine process heat out stream represents heat rejected to cooling water and ultimately to ambient via the cooling tower. The same is true of the condenser heat out stream. The CO_2 compressor intercooler load is included in the Econamine process heat out stream.

Exhibit 5-20 Case 14 Heat and Mass Balance, NGCC with CO_2 Capture

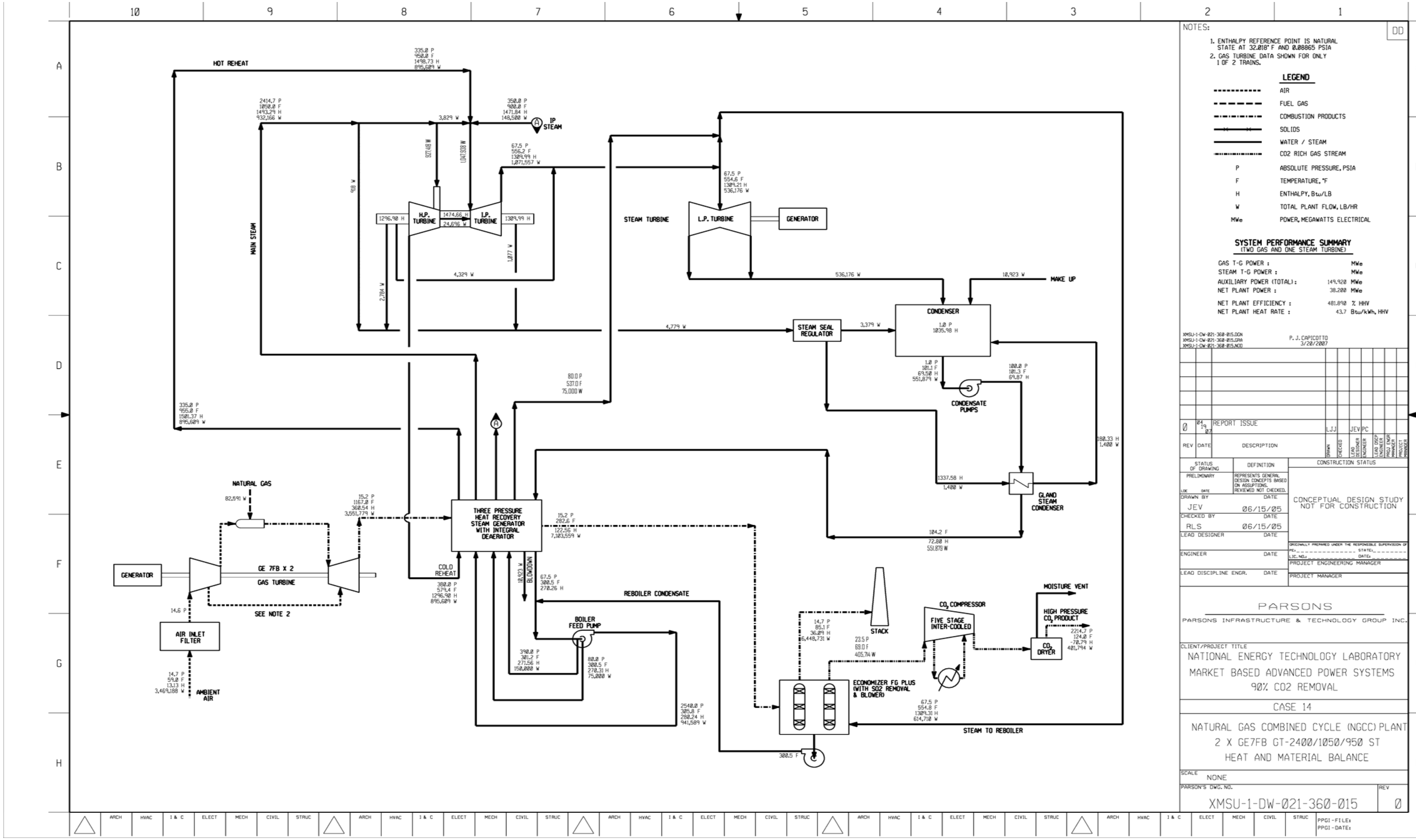

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Exhibit 5-21 Case 14 Overall Energy Balance (0°C [32°F] Reference)

	HHV	Sensible + Latent	Power	Total
Heat In (MMBtu/hr)				
Natural Gas	3,764.8	5.7		3,770.5
Ambient Air		91.1		91.1
Raw Water Makeup		49.7		49.7
Auxiliary Power			125.3	125.3
Totals	**3,764.8**	**146.5**	**125.3**	**4036.6**
Heat Out (MMBtu/hr)				
Flue Gas Exhaust		232.7		232.7
Condenser		522.0		522.0
Econamine Process		1463.8		1463.8
Cooling Tower Blowdown		25.1		25.1
CO_2 Product		(28.4)		(28.4)
Process Losses (1)		17.1		17.1
Power			1,804.4	1,804.4
Totals	**0.0**	**2,232.2**	**1,804.4**	**4,036.6**

(1) Process Losses are calculated by difference and reflect various boiler, turbine, and other heat and work losses. Aspen flowsheet balance is within 0.5 percent.

5.2.9 CASE 14 MAJOR EQUIPMENT LIST

Major equipment items for the NGCC plant with CO_2 capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 5.2.10. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

ACCOUNT 1 COAL AND SORBENT HANDLING

N/A

ACCOUNT 2 FUEL AND SORBENT PREPARATION AND FEED

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	56 m3/min @ 3.1 MPa (1,990 acfm @ 450 psia) 41 cm (16 in) standard wall pipe	16 km (10 mile)	0
2	Gas Metering Station	--	56 m3/min (1,990 acfm)	1	0

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	348,261 liters (92,000 gal)	2	0
2	Condensate Pumps	Vertical canned	2,309 lpm @ 85 m H2O (610 gpm @ 280 ft H2O)	2	1
3	Boiler Feedwater Pump	Horizontal, split case, multi-stage, centrifugal, with interstage bleed for IP and LP feedwater	HP water: 3,937 lpm @ 2,103 m H2O (1,040 gpm @ 6,900 ft H2O) IP water: 757 lpm @ 274 m H2O (200 gpm @ 900 ft H2O) LP water: 303 lpm @ 09 m H2O (80 gpm @ 30 ft H2O)	2	1
4	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/h, 2.8 MPa, 343°C (40,000 lb/h, 400 psig, 650°F)	1	0
5	Service Air Compressors	Flooded Screw	13 m3/min @ 0.7 MPa (450 scfm @ 100 psig)	2	1
6	Instrument Air Dryers	Duplex, regenerative	13 m3/min (450 scfm)	2	1
7	Closed Cycle Cooling Heat Exchangers	Plate and frame	40 MMkJ/hr (38 MMBtu/hr)	2	0
8	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	15,520 lpm @ 21 m H2O (4,100 gpm @ 70 ft H2O)	2	1
9	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 107 m H2O (1,000 gpm @ 350 ft H2O)	1	1
10	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 76 m H2O (700 gpm @ 250 ft H2O)	1	1
11	Raw Water Pumps	Stainless steel, single suction	10,978 lpm @ 18 m H2O (2,900 gpm @ 60 ft H2O)	2	1
12	Filtered Water Pumps	Stainless steel, single suction	174 lpm @ 49 m H2O (46 gpm @ 160 ft H2O)	2	1
13	Filtered Water Tank	Vertical, cylindrical	166,559 liter (44,000 gal)	1	0
14	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly and electro-deionization unit	379 lpm (100 gpm)	1	0
15	Liquid Waste Treatment System		10 years, 24-hour storm	1	0

ACCOUNT 4 GASIFIER, BOILER AND ACCESSORIES

N/A

ACCOUNT 5B CARBON DIOXIDE RECOVERY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Econamine FG Plus	Amine-based carbon dioxide capture system	Flue gas flow rate: 1,772,187 kg/h (3,907,000 lb/h), Inlet CO2 concentration: 6.3 wt%	2	0
2	Carbon Dioxide Compression System	Integrally geared, multi-stage centrifugal	100,698 kg/h @ 15.3 MPa (222,000 lb/h @ 2,215 psia)	2	0

ACCOUNT 6 COMBUSTION TURBINE GENERATORS AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gas Turbine	Advanced F class w/ dry low-NOx burner	185 MW	2	0
2	Gas Turbine Generator	TEWAC	210 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	2	0

ACCOUNT 7 WASTE HEAT BOILER, DUCTING, AND STACK

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	CS plate, type 409SS liner	46 m (150 ft) high x 4.5 m (15 ft) diameter	2	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	Main steam - 232,553 kg/h, 16.5 MPa/566°C (512,691 lb/h, 2,400 psig/1,050°F) Reheat steam - 223,433 kg/h, 2.3 MPa/510°C (492,585 lb/h, 335 psig/950°F)	2	0
3	SCR Reactor	Space for spare layer	1,610,255 kg/h (3,550,000 lb/h)	2	0
4	SCR Catalyst	--	Space available for an additional catalyst layer	1 layer	0
5	Dilution Air Blowers	Centrifugal	21 m3/min @ 91 cm WG (750 scfm @ 36 in WG)	2	1
6	Ammonia Feed Pump	Centrifugal	3.8 lpm @ 82 m H2O (1 gpm @ 270 ft H2O)	2	1
7	Ammonia Storage Tank	Horizontal tank	87,065 liter (23,000 gal)	1	0

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.
1	Steam Turbine	Tandem compound, HP, IP, and two-flow LP turbines	158 MW 16.5 MPa/566°C/510°C (2400 psig/ 1050°F/950°F)	1
2	Steam Turbine Generator	Hydrogen cooled, static excitation	180 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1
3	Steam Bypass	One per HRSG	50% steam flow @ design steam conditions	2
4	Surface Condenser	Single pass, divided waterbox including vacuum pumps	601 MMkJ/hr, (570 MMBtu/hr), Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	503,464 lpm @ 30.5 m (133,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT 2,393 MMkJ/hr (2,270 MMBtu/hr) heat load	1	0

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

N/A

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	24 kV/345 kV, 210 MVA, 3-ph, 60 Hz	2	0
2	STG Transformer	Oil-filled	24 kV/345 kV, 130 MVA, 3-ph, 60 Hz	1	0
3	Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 41 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 6 MVA, 3-ph, 60 Hz	1	1
5	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	2	0
6	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
7	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
8	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
9	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

ACCOUNT 12 INSTRUMENTATION AND CONTROL

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

5.2.10 CASE 14 – COST ESTIMATING

The cost estimating methodology was described previously in Section 2.6. Exhibit 5-22 shows the total plant capital cost summary organized by cost account and Exhibit 5-23 shows a more detailed breakdown of the capital costs. Exhibit 5-24 shows the initial and annual O&M costs.

The estimated TPC of the NGCC with CO_2 capture is $1,169/kW. Process contingency represents 5.0 percent of the TPC and project contingency represents 13.3 percent. The 20-year LCOE, including CO_2 TS&M costs of 2.9 mills/kWh, is 97.4 mills/kWh.

Exhibit 5-22 Case 14 Total Plant Cost Summary

Client: USDOE/NETL **Report Date:** 10-May-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 14 - NGCC w/ CO2
Plant Size: 481.9 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
2	COAL & SORBENT PREP & FEED	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
3	FEEDWATER & MISC. BOP SYSTEMS	$23,544	$4,970	$8,285	$0	$0	**$36,798**	$3,088	$0	$6,473	**$46,360**	$96
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.2	Syngas Cooling	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.3	ASU/Oxidant Compression	$0	$0	w/equip.	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.4-4.9	Other Gasification Equipment	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
	SUBTOTAL 4	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
5	Gas Cleanup & Piping	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
5B	CO_2 REMOVAL & COMPRESSION	$121,446	$0	$35,469	$0	$0	**$156,915**	$13,337	$27,564	$39,563	**$237,380**	$493
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$72,000	$0	$4,588	$0	$0	**$76,588**	$6,456	$0	$8,304	**$91,348**	$190
6.2-6.9	Combustion Turbine Other	$0	$681	$709	$0	$0	**$1,390**	$116	$0	$301	**$1,807**	$4
	SUBTOTAL 6	**$72,000**	**$681**	**$5,298**	**$0**	**$0**	**$77,979**	**$6,571**	**$0**	**$8,606**	**$93,156**	**$193**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$32,000	$0	$4,200	$0	$0	**$36,200**	$3,060	$0	$3,926	**$43,186**	$90
7.2-7.9	SCR System, Ductwork and Stack	$1,177	$881	$1,044	$0	$0	**$3,101**	$263	$0	$544	**$3,908**	$8
	SUBTOTAL 7	**$33,177**	**$881**	**$5,244**	**$0**	**$0**	**$39,301**	**$3,323**	**$0**	**$4,470**	**$47,094**	**$98**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$19,753	$0	$3,134	$0	$0	**$22,887**	$1,964	$0	$2,485	**$27,336**	$57
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$7,020	$606	$4,906	$0	$0	**$12,532**	$1,003	$0	$1,902	**$15,437**	$32
	SUBTOTAL 8	**$26,772**	**$606**	**$8,041**	**$0**	**$0**	**$35,419**	**$2,967**	**$0**	**$4,387**	**$42,774**	**$89**
9	COOLING WATER SYSTEM	$8,060	$6,365	$5,482	$0	$0	**$19,908**	$1,638	$0	$3,040	**$24,585**	$51
10	ASH/SPENT SORBENT HANDLING SYS	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
11	ACCESSORY ELECTRIC PLANT	$15,809	$5,267	$9,893	$0	$0	**$30,969**	$2,356	$0	$3,779	**$37,104**	$77
12	INSTRUMENTATION & CONTROL	$6,914	$723	$5,986	$0	$0	**$13,622**	$1,151	$681	$1,772	**$17,227**	$36
13	IMPROVEMENTS TO SITE	$1,643	$893	$4,406	$0	$0	**$6,942**	$611	$0	$1,511	**$9,063**	$19
14	BUILDINGS & STRUCTURES	$0	$3,885	$4,066	$0	$0	**$7,952**	$644	$0	$1,289	**$9,886**	$21
	TOTAL COST	**$309,365**	**$24,270**	**$92,170**	**$0**	**$0**	**$425,805**	**$35,687**	**$28,245**	**$74,891**	**$564,628**	**$1,172**

Exhibit 5-23 Case 14 Total Plant Cost Details

	Client:	USDOE/NETL							**Report Date:**		10-May-07	
	Project:	Bituminous Baseline Study										
				TOTAL PLANT COST SUMMARY								
	Case:	Case 14 - NGCC w/ CO2										
	Plant Size:	481.9 MW,net		**Estimate Type:**		Conceptual			**Cost Base (Dec)**		2006	($x1000)

Acct		Equipment	Material	Labor		Sales	Bare Erected	Eng'g CM	Contingencies		TOTAL PLANT COST	
No.	**Item/Description**	**Cost**	**Cost**	**Direct**	**Indirect**	**Tax**	**Cost $**	**H.O.& Fee**	**Process**	**Project**	**$**	**$/kW**
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.2	Coal Stackout & Reclaim	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.3	Coal Conveyors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.4	Other Coal Handling	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.5	Sorbent Receive & Unload	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.6	Sorbent Stackout & Reclaim	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.7	Sorbent Conveyors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.8	Other Sorbent Handling	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.9	Coal & Sorbent Hnd.Foundations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 1.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying incl w/2.3	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.2	Prepared Coal Storage & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.3	Slurry Prep & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.4	Misc.Coal Prep & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.5	Sorbent Prep Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.6	Sorbent Storage & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.7	Sorbent Injection System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.8	Booster Air Supply System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.9	Coal & Sorbent Feed Foundation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 2.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	$2,425	$2,530	$2,082	$0	$0	$7,037	$579	$0	$1,142	$8,758	$18
3.2	Water Makeup & Pretreating	$2,271	$237	$1,185	$0	$0	$3,692	$312	$0	$801	$4,805	$10
3.3	Other Feedwater Subsystems	$1,116	$378	$318	$0	$0	$1,813	$145	$0	$294	$2,252	$5
3.4	Service Water Systems	$270	$552	$1,791	$0	$0	$2,613	$226	$0	$568	$3,407	$7
3.5	Other Boiler Plant Systems	$1,815	$696	$1,614	$0	$0	$4,126	$346	$0	$671	$5,143	$11
3.6	FO Supply Sys & Nat Gas	$13,946	$458	$399	$0	$0	$14,803	$1,246	$0	$2,407	$18,456	$38
3.7	Waste Treatment Equipment	$815	$0	$467	$0	$0	$1,282	$111	$0	$279	$1,671	$3
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	$885	$119	$428	$0	$0	$1,432	$124	$0	$311	$1,866	$4
	SUBTOTAL 3.	**$23,544**	**$4,970**	**$8,285**	**$0**	**$0**	**$36,798**	**$3,088**	**$0**	**$6,473**	**$46,360**	**$96**
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries (E-GAS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.2	Syngas Cooling (w/ 4.1	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.3	ASU/Oxidant Compression	$0	$0	w/equip.	$0	$0	$0	$0	$0	$0	$0	$0
4.4	LT Heat Recovery & FG Saturation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.5	Misc. Gasification Equipment	w/4.1&4.2	$0	w/4.1&4.2	$0	$0	$0	$0	$0	$0	$0	$0
4.6	Other Gasification Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.8	Major Component Rigging		$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.9	Gasification Foundations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 4.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**

Exhibit 5-23 Case 14 Total Plant Cost Details (Continued)

Client:	USDOE/NETL
Project:	Bituminous Baseline Study
Case:	Case 14 - NGCC w/ CO2
Plant Size:	481.9 MW,net
Estimate Type:	Conceptual
Report Date:	10-May-07
Cost Base (Dec)	2006 ($x1000)

TOTAL PLANT COST SUMMARY

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5A	GAS CLEANUP & PIPING											
5A.1	Double Stage Selexol	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.2	Elemental Sulfur Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.3	Mercury Removal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.4	Shift Reactors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.6	Blowback Gas Systems	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.7	Fuel Gas Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.9	HGCU Foundations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 5.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
5B	CO2 REMOVAL & COMPRESSION											
5B.1	CO2 Removal System	$106,600	$0	$31,220	$0	$0	$137,821	$11,715	$27,564	$35,420	$212,519	$441
5B.2	CO2 Compression & Drying	$14,846	$0	$4,248	$0	$0	$19,094	$1,623	$0	$4,143	$24,860	$52
	SUBTOTAL 5.	**$121,446**	**$0**	**$35,469**	**$0**	**$0**	**$156,915**	**$13,337**	**$27,564**	**$39,563**	**$237,380**	**$493**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$72,000	$0	$4,588	$0	$0	$76,588	$6,456	$0	$8,304	$91,348	$190
6.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.3	Compressed Air Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.9	Combustion Turbine Foundations	$0	$681	$709	$0	$0	$1,390	$116	$0	$301	$1,807	$4
	SUBTOTAL 6.	**$72,000**	**$681**	**$5,298**	**$0**	**$0**	**$77,979**	**$6,571**	**$0**	**$8,606**	**$93,156**	**$193**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$32,000	$0	$4,200	$0	$0	$36,200	$3,060	$0	$3,926	$43,186	$90
7.2	SCR System	$1,177	$494	$694	$0	$0	$2,365	$202	$0	$385	$2,952	$6
7.3	Ductwork	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.4	Stack	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.9	HRSG,Duct & Stack Foundations	$0	$386	$349	$0	$0	$736	$61	$0	$159	$956	$2
	SUBTOTAL 7.	**$33,177**	**$881**	**$5,244**	**$0**	**$0**	**$39,301**	**$3,323**	**$0**	**$4,470**	**$47,094**	**$98**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$19,753	$0	$3,134	$0	$0	$22,887	$1,964	$0	$2,485	$27,336	$57
8.2	Turbine Plant Auxiliaries	$135	$0	$303	$0	$0	$438	$38	$0	$48	$524	$1
8.3	Condenser & Auxiliaries	$2,643	$0	$845	$0	$0	$3,488	$297	$0	$378	$4,163	$9
8.4	Steam Piping	$4,242	$0	$2,794	$0	$0	$7,036	$535	$0	$1,136	$8,707	$18
8.9	TG Foundations	$0	$606	$964	$0	$0	$1,570	$132	$0	$341	$2,043	$4
	SUBTOTAL 8.	**$26,772**	**$606**	**$8,041**	**$0**	**$0**	**$35,419**	**$2,967**	**$0**	**$4,387**	**$42,774**	**$89**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$5,487	$0	$749	$0	$0	$6,236	$527	$0	$676	$7,439	$15
9.2	Circulating Water Pumps	$1,832	$0	$117	$0	$0	$1,949	$149	$0	$210	$2,308	$5
9.3	Circ.Water System Auxiliaries	$141	$0	$19	$0	$0	$160	$14	$0	$17	$191	$0
9.4	Circ.Water Piping	$0	$4,191	$999	$0	$0	$5,191	$411	$0	$840	$6,442	$13
9.5	Make-up Water System	$325	$0	$430	$0	$0	$755	$64	$0	$123	$942	$2
9.6	Component Cooling Water Sys	$276	$330	$218	$0	$0	$824	$68	$0	$134	$1,026	$2
9.9	Circ.Water System Foundations& Structures	$0	$1,844	$2,950	$0	$0	$4,794	$404	$0	$1,040	$6,238	$13
	SUBTOTAL 9.	**$8,060**	**$6,365**	**$5,482**	**$0**	**$0**	**$19,908**	**$1,638**	**$0**	**$3,040**	**$24,585**	**$51**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Slag Dewatering & Cooling	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0
10.2	Gasifier Ash Depressurization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.3	Cleanup Ash Depressurization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.4	High Temperature Ash Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.5	Other Ash Rrecovery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.7	Ash Transport & Feed Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.8	Misc. Ash Handling Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.9	Ash/Spent Sorbent Foundation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 10.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**

Exhibit 5-23 Case 14 Total Plant Cost Details (Continued)

Client: USDOE/NETL **Report Date:** 10-May-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 14 - NGCC w/ CO2
Plant Size: 481.9 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$2,198	$0	$1,331	$0	$0	$3,529	$298	$0	$287	$4,114	$9
11.2	Station Service Equipment	$1,829	$0	$160	$0	$0	$1,989	$169	$0	$162	$2,321	$5
11.3	Switchgear & Motor Control	$2,330	$0	$399	$0	$0	$2,729	$226	$0	$296	$3,251	$7
11.4	Conduit & Cable Tray	$0	$1,140	$3,460	$0	$0	$4,600	$393	$0	$749	$5,743	$12
11.5	Wire & Cable	$0	$3,490	$2,194	$0	$0	$5,685	$369	$0	$908	$6,962	$14
11.6	Protective Equipment	$0	$520	$1,844	$0	$0	$2,364	$207	$0	$257	$2,828	$6
11.7	Standby Equipment	$91	$0	$86	$0	$0	$177	$15	$0	$19	$211	$0
11.8	Main Power Transformers	$9,361	$0	$131	$0	$0	$9,492	$644	$0	$1,014	$11,150	$23
11.9	Electrical Foundations	$0	$116	$287	$0	$0	$403	$34	$0	$87	$525	$1
	SUBTOTAL 11.	**$15,809**	**$5,267**	**$9,893**	**$0**	**$0**	**$30,969**	**$2,356**	**$0**	**$3,779**	**$37,104**	**$77**
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
12.3	Steam Turbine Control	w/8.1	$0	w/8.1	$0	$0	$0	$0	$0	$0	$0	$0
12.4	Other Major Component Control	$879	$0	$572	$0	$0	$1,451	$125	$73	$247	$1,896	$4
12.5	Signal Processing Equipment	W/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.6	Control Boards,Panels & Racks	$263	$0	$164	$0	$0	$427	$37	$21	$73	$557	$1
12.7	Computer & Accessories	$4,205	$0	$131	$0	$0	$4,336	$368	$217	$492	$5,413	$11
12.8	Instrument Wiring & Tubing	$0	$723	$1,413	$0	$0	$2,136	$161	$107	$361	$2,764	$6
12.9	Other I & C Equipment	$1,568	$0	$3,706	$0	$0	$5,273	$460	$264	$600	$6,597	$14
	SUBTOTAL 12.	**$6,914**	**$723**	**$5,986**	**$0**	**$0**	**$13,622**	**$1,151**	**$681**	**$1,772**	**$17,227**	**$36**
13	Improvements to Site											
13.1	Site Preparation	$0	$88	$1,766	$0	$0	$1,854	$164	$0	$404	$2,421	$5
13.2	Site Improvements	$0	$805	$1,007	$0	$0	$1,812	$159	$0	$394	$2,366	$5
13.3	Site Facilities	$1,643	$0	$1,633	$0	$0	$3,276	$288	$0	$713	$4,277	$9
	SUBTOTAL 13.	**$1,643**	**$893**	**$4,406**	**$0**	**$0**	**$6,942**	**$611**	**$0**	**$1,511**	**$9,063**	**$19**
14	Buildings & Structures											
14.1	Combustion Turbine Area	$0	$222	$119	$0	$0	$341	$27	$0	$55	$423	$1
14.2	Steam Turbine Building	$0	$1,593	$2,149	$0	$0	$3,742	$307	$0	$607	$4,656	$10
14.3	Administration Building	$0	$437	$300	$0	$0	$736	$59	$0	$119	$914	$2
14.4	Circulation Water Pumphouse	$0	$167	$84	$0	$0	$250	$20	$0	$40	$310	$1
14.5	Water Treatment Buildings	$0	$484	$447	$0	$0	$931	$75	$0	$151	$1,157	$2
14.6	Machine Shop	$0	$379	$245	$0	$0	$624	$49	$0	$101	$775	$2
14.7	Warehouse	$0	$245	$150	$0	$0	$394	$31	$0	$64	$489	$1
14.8	Other Buildings & Structures	$0	$73	$54	$0	$0	$127	$10	$0	$21	$158	$0
14.9	Waste Treating Building & Str.	$0	$287	$519	$0	$0	$805	$67	$0	$131	$1,003	$2
	SUBTOTAL 14.	**$0**	**$3,885**	**$4,066**	**$0**	**$0**	**$7,952**	**$644**	**$0**	**$1,289**	**$9,886**	**$21**
	TOTAL COST	**$309,365**	**$24,270**	**$92,170**	**$0**	**$0**	**$425,805**	**$35,687**	**$28,245**	**$74,891**	**$564,628**	**$1,172**

Exhibit 5-24 Case 14 Initial and Annual Operating and Maintenance Cost Summary

INITIAL & ANNUAL O&M EXPENSES					Cost Base (Dec)	2006
Case 14 - NGCC w/ CO2					Heat Rate-net(Btu/kWh):	7,813
					MWe-net:	482
					Capacity Factor: (%):	85
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate(base):	33.00	$/hour				
Operating Labor Burden:	30.00	% of base				
Labor O-H Charge Rate:	25.00	% of labor				
			Total			
Skilled Operator	1.0		1.0			
Operator	3.3		3.3			
Foreman	1.0		1.0			
Lab Tech's, etc.	1.0		1.0			
TOTAL-O.J.'s	6.3		6.3			
					Annual Cost $	Annual Unit Cost $/kW-net
Annual Operating Labor Cost					$2,378,839	$4.936
Maintenance Labor Cost					$4,034,866	$8.373
Administrative & Support Labor					$1,603,426	$3.327
TOTAL FIXED OPERATING COSTS					**$8,017,131**	**$16.637**
VARIABLE OPERATING COSTS						
						$/kWh-net
Maintenance Material Cost					**$6,052,299**	**$0.00169**
Consumables	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost		
Water(/1000 gallons)	0	3,370.32	1.00	**$0**	**$1,045,642**	**$0.00029**
Chemicals						
MU & WT Chem.(lb)	140,555.73	20,079.39	0.16	$21,888	$970,101	$0.00027
Carbon (Mercury Removal) (lb.)	0.00	0.00	1.00	$0	$0	$0.00000
COS Catalyst (lb)	0.00	0.00	0.60	$0	$0	$0.00000
MEA Solvent (ton)	342.00	0.48	2,142.40	$732,701	$319,046	$0.00009
Activated Carbon(lb)	210,384.00	576.00	1.00	$210,384	$178,704	$0.00005
Corrosion Inhibitor	1.00	0.00	0.00	$47,000	$2,250	$0.00000
SCR Catalyst (m3)	w/equip.	0.08	5,500.00	$0	$140,093	$0.00004
Ammonia (28% NH3) ton	54.94	7.85	190.00	$10,438	$462,620	$0.00013
Subtotal Chemicals				**$1,022,410**	**$2,072,814**	**$0.00058**
Other						
Supplemental Fuel(MBtu)	0.00	0.00	0.00	$0	$0	$0.00000
Gases,N2 etc.(/100scf)	0.00	0.00	0.00	$0	$0	$0.00000
L.P. Steam(/1000 pounds)	0.00	0.00	0.00	$0	$0	$0.00000
Subtotal Other				**$0**	**$0**	**$0.00000**
Waste Disposal						
Spent Mercury Catalyst (lb.)	0.00	0.00	0.00	$0	$0	$0.00000
Flyash (ton)	0.00	0.00	0.00	$0	$0	$0.00000
Bottom Ash(ton)	0.00	0.00	0.00	$0	$0	$0.00000
Subtotal-Waste Disposal				**$0**	**$0**	**$0.00000**
By-products & Emissions						
Sulfur(tons)	0.00	0.00	0.00	$0	$0	$0.00000
Subtotal By-Products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$1,022,410**	**$9,170,755**	**$0.00256**
Fuel(MMbtu)	2,710,805	90,360	6.75	**$18,297,932**	**$189,231,113**	**$0.05274**

5.3 NGCC CASE SUMMARY

The performance results of the two NGCC plant configurations modeled in this study are summarized in Exhibit 5-25.

Exhibit 5-25 Estimated Performance and Cost Results for NGCC Cases

	NGCC Advanced F Class Case 13	NGCC Advanced F Class Case 14
CO_2 Capture	No	Yes
Gross Power Output (kW_e)	570,200	520,090
Auxiliary Power Requirement (kW_e)	9,840	38,200
Net Power Output (kW_e)	560,360	481,890
Coal Flowrate (lb/hr)	N/A	N/A
Natural Gas Flowrate (lb/hr)	165,182	165,182
HHV Thermal Input (kW_{th})	1,103,363	1,103,363
Net Plant HHV Efficiency (%)	50.8%	43.7%
Net Plant HHV Heat Rate (Btu/kW-hr)	6,719	7,813
Raw Water Usage, gpm	2,511	3,901
Total Plant Cost ($ x 1,000)	310,710	564,628
Total Plant Cost ($/kW)	554	1,172
LCOE (mills/kWh)[1]	68.4	97.4
CO_2 Emissions (lb/MWh)[2]	783	85.8
CO_2 Emissions (lb/MWh)[3]	797	93
SO_2 Emissions (lb/MWh)[2]	Negligible	Negligible
NOx Emissions (lb/MWh)[2]	0.060	0.066
PM Emissions (lb/MWh)[2]	Negligible	Negligible
Hg Emissions (lb/MWh)[2]	Negligible	Negligible

[1] Based on an 85% capacity factor
[2] Value is based on gross output
[3] Value is based on net output

The TPC for the two NGCC cases is shown in Exhibit 5-26. The capital cost of the non-capture case, $554/kW, is the lowest of all technologies studied by at least 64 percent. Addition of CO_2 capture more than doubles the capital cost, but NGCC with capture is still the least capital intensive of all the capture technologies by at least 51 percent. The process contingency included for the Econamine process totals $57/kW, which represents 5 percent of TPC.

The LCOE for NGCC cases is heavily dependent on the price of natural gas as shown in Exhibit 5-27. The fuel component of LCOE represents 78 percent of the total in the non-capture case and 63 percent of the total in the CO_2 capture case. Because LCOE has a small capital component, it is less sensitive to capacity factor than the more capital intensive PC and IGCC cases. The decrease in net kilowatt-hours produced is nearly offset by a corresponding decrease in fuel cost. The CO_2 TS&M component of LCOE is only 3 percent of the total in the CO_2 capture case.

Exhibit 5-26 TPC of NGCC Cases

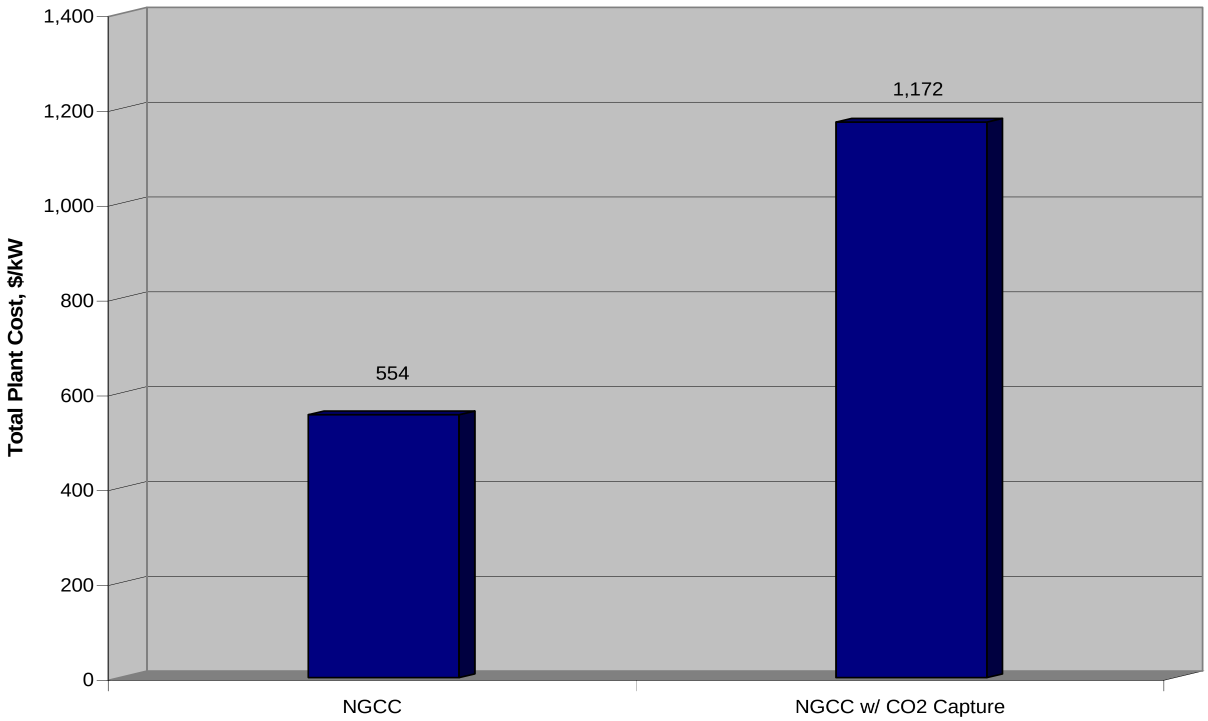
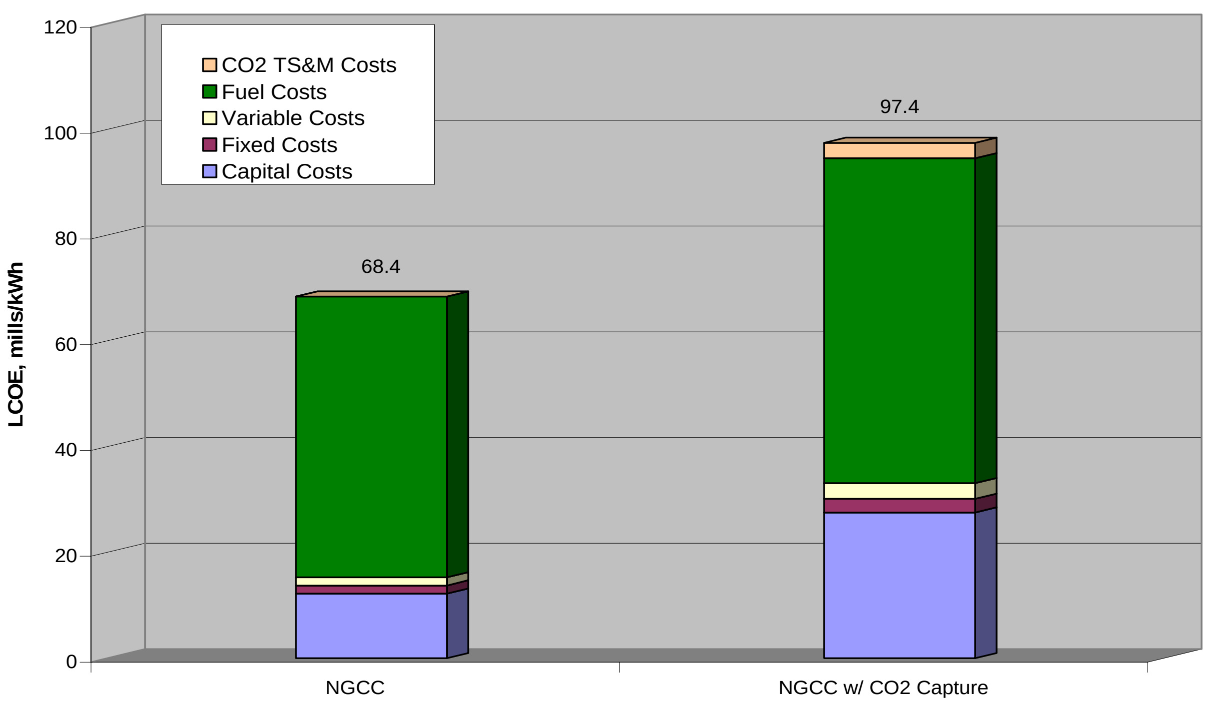


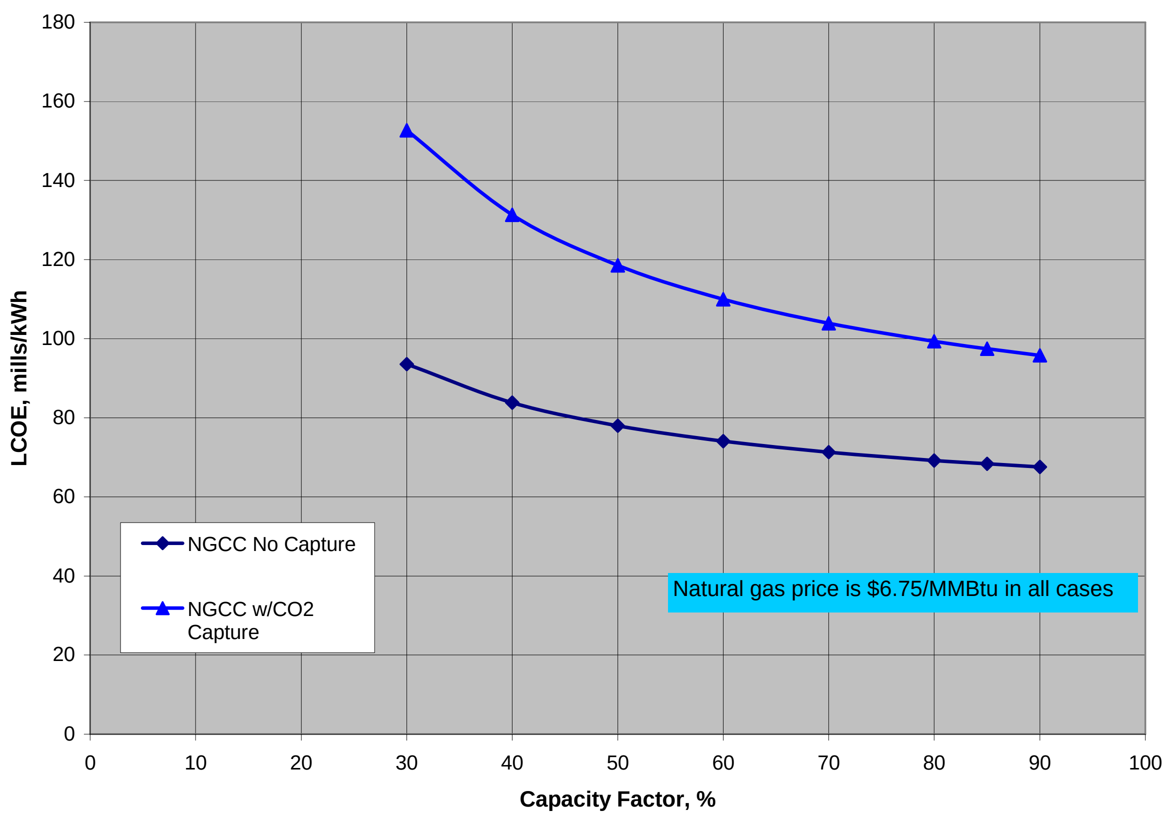
Exhibit 5-27 LCOE of NGCC Cases



The sensitivity of NGCC to capacity factor is shown in Exhibit 5-28. Unlike the PC and IGCC case, NGCC is relatively insensitive to capacity factor but highly sensitive to fuel cost as shown in Exhibit 5-29. A 33 percent increase in natural gas price (from $6 to $8/MMBtu) results in a LCOE increase of 25 percent in the non-capture case and 20 percent in the CO_2 capture case. Because of the higher capital cost in the CO_2 capture case, the impact of fuel price changes is slightly diminished.

As presented in Section 2.4 the cost of CO_2 capture was calculated in two ways, CO_2 removed and CO_2 avoided. In the NGCC case the cost of CO_2 removed is $70/ton and the cost of CO_2 avoided is $83/ton. The high cost relative to PC and IGCC technologies is mainly due to the much smaller amount of CO_2 generated by NGCC and therefore captured in the Econamine process.

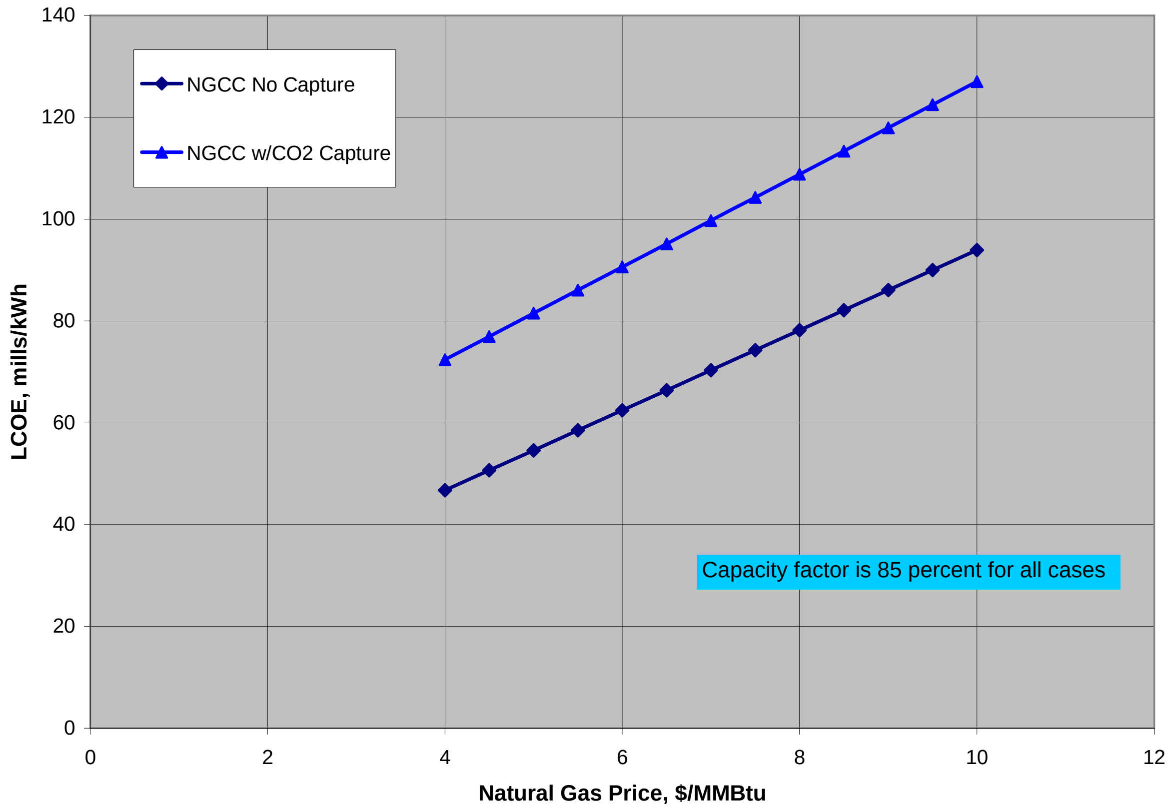
Exhibit 5-28 Sensitivity of LCOE to Capacity Factor in NGCC Cases



The following observations can be made regarding plant performance with reference to Exhibit 5-25:

- The efficiency of the NGCC case with no CO_2 capture is 50.8 percent (HHV basis). Gas Turbine World provides estimated performance for an advanced F class turbine operated on natural gas in a combined cycle mode, and the reported efficiency is 57.5 percent (LHV basis). [66] Adjusting the result from this study to an LHV basis results in an efficiency of 56.3 percent.

Exhibit 5-29 Sensitivity of LCOE to Fuel Price in NGCC Cases



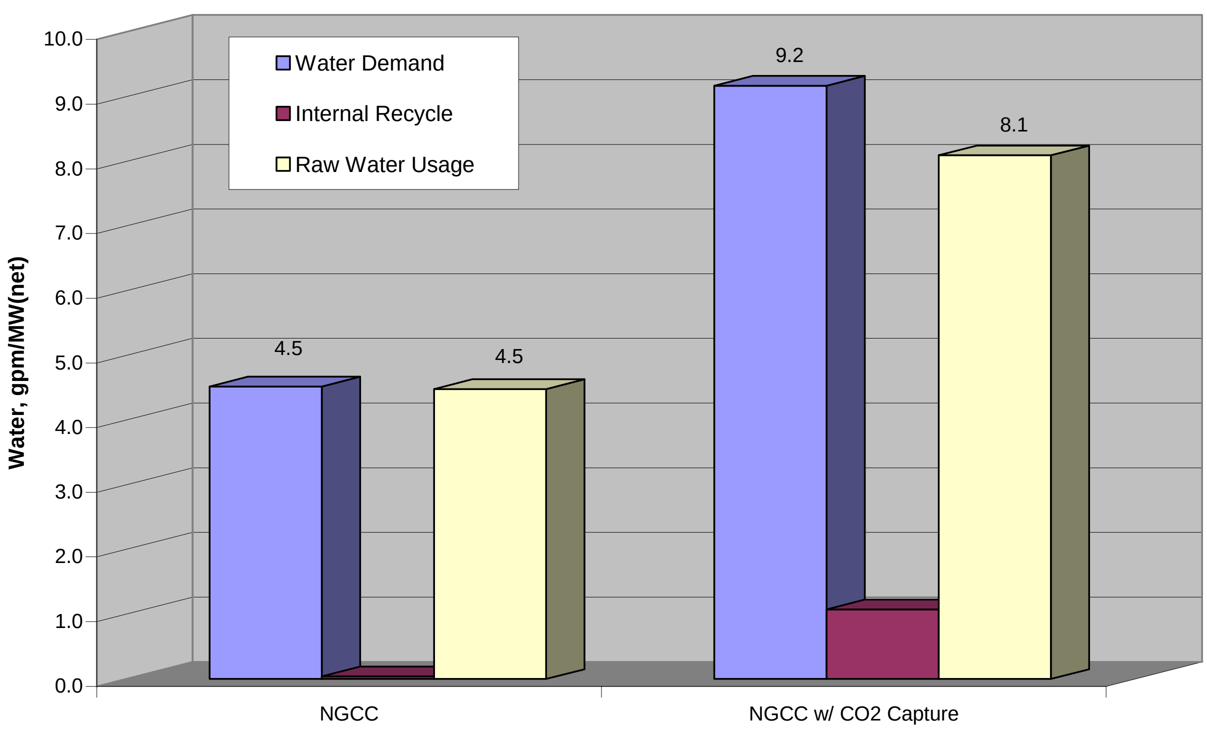
- The efficiency penalty to add CO_2 capture in the NGCC case is 7.1 percentage points. The efficiency reduction is caused primarily by the auxiliary loads of the Econamine system and CO_2 compression as well as the significantly increased cooling water requirement, which increases the auxiliary load of the circulating water pumps and the cooling tower fan. CO_2 capture results in a 28 MW increase in auxiliary load compared to the non-capture case.
- The energy penalty for NGCC is less than PC (7.1 percentage points for NGCC compared to 11.9 percentage points for PC) mainly because natural gas has a lower carbon intensity than coal. In the PC cases, about 589,670 kg/h (1.3 million lb/h) of CO_2 must be captured and compressed while in the NGCC case only about 181,437 kg/h (400,000 lb/h) is captured and compressed.
- A study assumption is that the natural gas contains no PM or Hg, resulting in negligible emissions of both.
- This study also assumes that the natural gas contains no sulfur compounds, resulting in negligible emissions of SO_2. As noted previously in the report, if the natural gas contained the maximum allowable amount of sulfur per EPA's pipeline natural gas specification, the resulting SO_2 emissions would be 21 tonnes/yr (23 tons/yr), or 0.00195 lb/MMBtu.

- NOx emissions are identical for the two NGCC cases on a heat input and mass basis. This is a result of the fixed output from the gas turbine (25 ppmv at 15 percent O_2) and the fixed efficiency of the SCR (90 percent).

The normalized water demand, internal recycle and raw water usage are shown in Exhibit 5-30 for the NGCC cases. The following observations can be made:

- Normalized water demand increases 103 percent and normalized raw water usage 81 percent in the CO_2 capture case. The high cooling water demand of the Econamine process results in a large increase in cooling tower makeup requirements.
- Cooling tower makeup comprises over 99 percent of the raw water usage in both NGCC cases. The only internal recycle stream in the non-capture case is the boiler feedwater blowdown, which is recycled to the cooling tower. In the CO_2 capture case condensate is recovered from the flue gas as it is cooled to the absorber temperature of 32°C (89°F) and is also recycled to the cooling tower.

Exhibit 5-30 Water Usage in NGCC Cases



6 REVISION CONTROL

The initial issue of this report was made public on May 15, 2007. Subsequent to the issue date, updates have been made to various report sections. These additions were made for clarification and aesthetic purposes and to correct an error made in determining the Econamine cooling water requirement in the PC and NGCC CO_2 capture cases. The water balances and water usage comparison exhibits were updated accordingly. In addition, the PC and NGCC energy balance tables contained errors which have been corrected in this version of the report. None of the changes affect the conclusions previously drawn. Exhibit 6-1 contains information added, changed or deleted in successive revisions.

Exhibit 6-1 Record of Revisions

Revision Number	Revision Date	Description of Change	Comments
1	8/23/07	Added disclaimer to Executive Summary and Introduction	Disclaimer involves clarification on extent of participation of technology vendors.
		Removed reference to Cases 7 and 8 in Exhibits ES-1 and 1-1.	SNG cases moved to Volume 2 of this report as explained in the Executive Summary and Section 1.
		Added Section 2.8	Explains differences in IGCC TPC estimates in this study versus costs reported by other sources.
		Added Exhibit ES-14	Mercury emissions are now shown in a separate exhibit from SO_2, NOx and PM because of the different y-axis scale.
		Corrected PC and NGCC CO_2 capture case water balances	The Econamine process cooling water requirement for the PC and NGCC CO_2 capture cases was overstated and has been revised.
		Replaced Exhibits ES-4, 3-121, 4-52 and 5-30	The old water usage figures were in gpm (absolute) and in the new figures the water numbers are normalized by net plant output.
		Update Selexol process description	Text was added to Section 3.1.5 to describe how H_2 slip was handled in the models.

Revision Number	Revision Date	Description of Change	Comments
		Revised PC and NGCC CO_2 capture case energy balances (Exhibits 4-21, 4-42 and 5-21)	The earlier version of the energy balances improperly accounted for the Econamine process heat losses. The heat removed from the Econamine process is rejected to the cooling tower.
		Corrected Exhibit 5-11 and Exhibit 5-21	Sensible heat for combustion air in the two NGCC cases was for only one of the two combustion turbines – corrected to account for both turbines

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DEPARTMENT OF NATURAL RESOURCES
PUBLIC SERVICE COMMISSION OF WISCONSIN

INTEGRATED GASIFICATION COMBINED-CYCLE TECHNOLOGY DRAFT REPORT

BENEFITS, COSTS, AND PROSPECTS FOR FUTURE USE IN WISCONSIN

Docket 9300-GF-176

June 2006

DEPARTMENT OF NATURAL RESOURCES
PUBLIC SERVICE COMMISSION OF WISCONSIN

IGCC: BENEFITS, COSTS, AND PROSPECTS FOR FUTURE USE IN WISCONSIN

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Executive Summary

Governor Jim Doyle initiated a review of Integrated Gasification Combined-Cycle Generation (IGCC) technology as a part of his Conserve Wisconsin agenda in August 2005. The Governor directed the Department of Natural Resources and the Public Service Commission of Wisconsin to investigate IGCC technology and its potential for Wisconsin. The agencies convened a broad stakeholder group, including electric providers, environmental organizations, consumer advocacy and labor groups, and state research institutions, to review the technology and compare it to conventional coal power plant designs. The stakeholder group, as well as interested members of the public, advised the agencies and provided feedback to this report.

Coal is the dominant source of fuel for electricity generation in Wisconsin. It is a cheap fuel source and abundantly available in the U.S., but it comes with a cost to the environment and public health. IGCC offers the possibility of continuing to rely upon coal for power generation while reducing coal's impact to society. Wisconsin is in the midst of a major energy infrastructure building cycle, and in the next 10 years, the state will make infrastructure decisions that will likely impact our economy and environment for the next half century. IGCC may offer an avenue to continue to rely upon cheap coal while further safeguarding the environment. This report reviews the costs, benefits and prospects for the future use of IGCC in the state.

Rather than burning coal, gasification is a process by which coal, under high pressure and temperature, is transformed into gas prior to combustion. The resultant gas, called syngas, can be cleaned of pollutants prior to firing in a turbine. With conventional coal technology, pollutants must be stripped out after combustion, in the exhaust, which is both more difficult and more expensive. Pre-combustion removal using the gasification process also results in lower pollution volumes, lowering disposal costs. However, only two IGCC plants produce electricity commercially in the U.S. today (five total in the world), so there is limited operating experience with IGCC.

This analysis compares IGCC with supercritical pulverized coal (SCPC) technology using two different types of coal. SCPC is an efficient conventional coal technology; SCPC plants are now under construction in both the Milwaukee and Wausau areas.

The investigation showed that IGCC, before considering the treatment of carbon dioxide, has a cost premium over SCPC of $5 to $7/megawatthour (MWh) of energy generated. A typical coal-fired baseload plant generally produces electricity for $35 to $55/MWh of energy generated, thus a $5 to $7 premium is a sizable difference.

As there is limited construction and operating experience with IGCC, there is a range of uncertainty in determining costs for IGCC. This analysis found that the major factors that vary the final cost of electricity for IGCC are construction costs, operational reliability, and plant heating efficiency. With

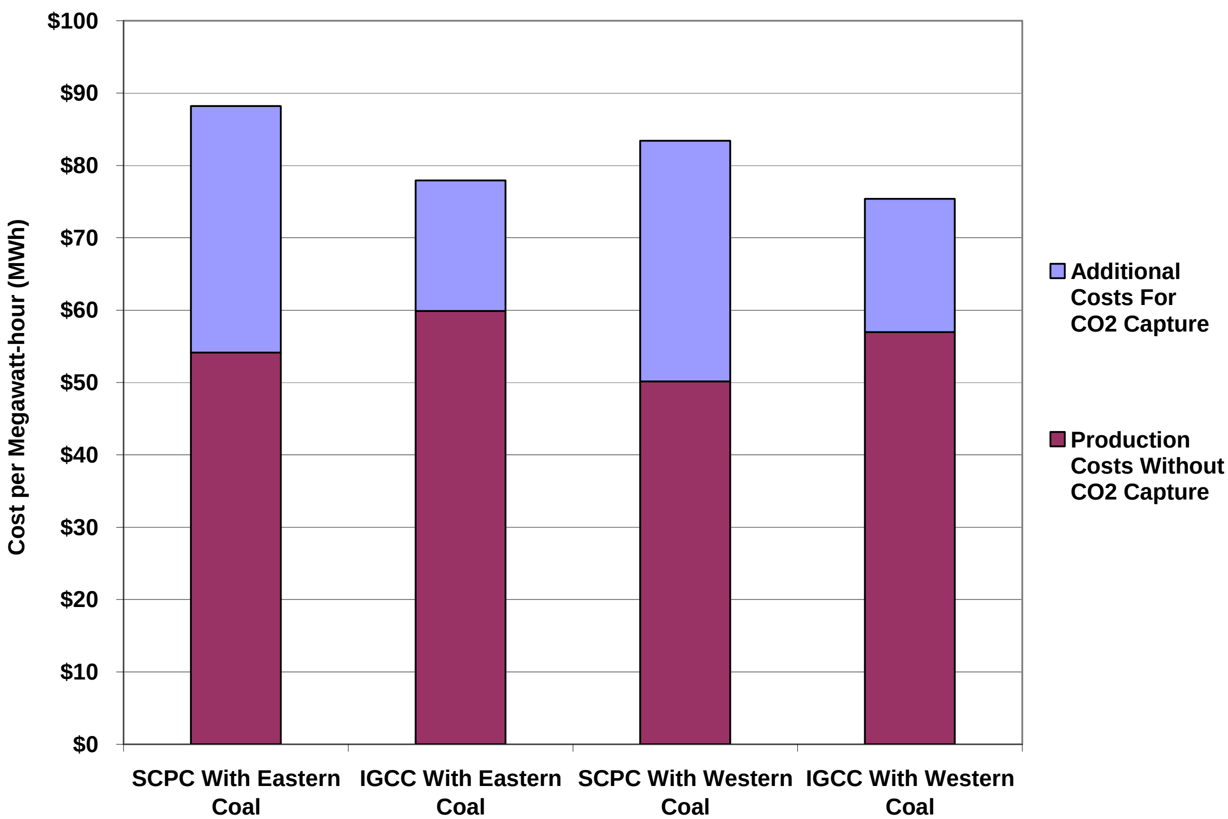
more experience, these three variables could change, dramatically altering the cost difference between IGCC and SCPC.

The fourth variable that currently alters the cost difference between IGCC and SCPC is the treatment of carbon dioxide. Carbon dioxide is a greenhouse gas that causes global warming; the gas is not currently regulated in the U.S., but there is much speculation that Congress may take action to regulate carbon dioxide emissions in the near future.

As described above, pollutants, including carbon dioxide, are easier to strip out of IGCC than SCPC. This means that should a carbon dioxide tax be imposed, IGCC will have an advantage both in terms of cost and technology in the near term. This analysis showed that adding carbon dioxide capture capability to IGCC and SCPC raised the final cost of electricity for both plants significantly, to over $75/MWh of energy generated. However, the cost premium between IGCC and SCPC reversed, such that the final cost of electricity from an IGCC plant with carbon capture technology was approximately $10/MWh less than SCPC.

Figure ES-1 illustrates this reversal. Without carbon capture capability, IGCC is the higher cost option. With carbon capture capability, IGCC is the lower cost option.

Figure ES-1 IGCC and SCPC with and without Carbon Capture Technology



Carbon dioxide capture is only part of the picture, however. Once captured, the carbon dioxide must be transported and stored, or sequestered. Current research is investigating the possibility of storing carbon dioxide in depleted oil fields or coal beds, salt domes or saline aquifiers. Geologically, Wisconsin has none of these natural storage reservoirs, so transportation concerns are critical for the state.

Transportation and storage options are early in development and further investigation is needed before they can be considered commercially viable options.

Should the state decide to pursue IGCC as a matter of environmental policy, there are financing options that would help to reduce the cost. Grants, tax or credit-based incentives, or favorable regulatory treatment are all options to consider. This analysis showed that the incentive with the greatest financial impact is securitized financing.

Securitized financing alters the debt-to-equity ratio of a project, allowing a utility to fund a greater portion of a project through low-interest bonds. These bonds must be backed by a dedicated revenue stream (*e.g.* a utility's customers). This type of financing, however, shifts much of the project risk from utility investors (shareholders and bond holders) to utility customers.[1] Depending upon the debt-to-equity ratio assumed, securitized financing can dramatically lower the cost of IGCC. Wis. Stat. § 196.027, the "environmental trust financing" statute, allows this type of financing for pollution control equipment. However, there would have to be a specific policy determination by the state, as well as a legislative change, to extend the special financing arrangement to IGCC.

Thus, pursuing IGCC has become a question of timing: build now and risk reliability problems and higher construction costs as an early adopter or wait to learn from the experience of other projects and risk obsolete conventional coal technology and further environmental degradation. This question is particularly timely for Wisconsin given its near-term building needs and the long operating life of baseload plants. The state has a window in the next 10 years in which major decisions will be made about energy infrastructure needs. Which alternatives are chosen will depend upon how much weight a decision-maker places on technological risk, cost considerations, environmental protection, potential changes in federal air policy, and financial alternatives. This report attempts to shed light on how each of these areas impacts the choice of IGCC versus SCPC.

[1] By shifting risk to utility customers, relatively more bonds may be sold (a higher debt to equity ratio) and the yield on the bonds (interest paid) may be significantly lower.

1

Chapter 1: The Broader Picture

In recent years, Integrated Gasification Combined-Cycle (IGCC) electric generation has become a much debated topic in the electric utility industry. Concerns about global warming, an aging fleet of coal plants, new federal air standards, and the nation's continued thirst for electricity have converged to make "clean coal" a much desired development. In Wisconsin, a major energy infrastructure building cycle is under way, and, in the next ten years, the state will make infrastructure decisions that will likely impact our economy and environment for the next half century. Thus, the questions about IGCC are particularly timely for Wisconsin.

The need for electricity continues to grow in the state. Forecasts indicate that Wisconsin's demand for electricity will grow at approximately 2 percent per year through at least 2012.[2] While the Energy Efficiency and Renewables Act[3] recently enacted under the leadership of Governor Jim Doyle may help to slow some of this demand, significant energy infrastructure projects are under way in the state and more are anticipated in the near future. Additional baseload generation, the workhorse power plants that run nearly continuously throughout the year, may be needed. Although 1,853 megawatts (MW) of baseload generation are currently under construction or have been approved by the Public Service Commission (Commission or PSC),[4] at least four of the state's investor-owned utilities are reviewing the need for further baseload additions.

Coal is the dominant source of electricity production in Wisconsin. In 2005, 63 percent of the electricity produced in the state was from coal-fired power plants.[5] Although natural gas and nuclear could also supply baseload power needs, the recent volatility of natural gas prices and Wisconsin's moratorium on building nuclear plants[6] present additional obstacles for these power sources. Further, the U.S. possesses 26 percent of the world's known coal reserves and is the largest single holder of these reserves.[7] The U.S. Energy Information Agency (EIA) views coal as having a price advantage over natural gas over the long-run and concludes that coal use in the U.S. will almost double by 2030.[8] Thus, coal for power generation will likely be a mainstay in Wisconsin for decades to come.

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[2] Public Service Commission of Wisconsin. *2006-2012 Strategic Energy Assessment* (forthcoming). Assumes an industry average growth rate of 2.0 percent.
[3] 2005 Wisconsin Act 141.
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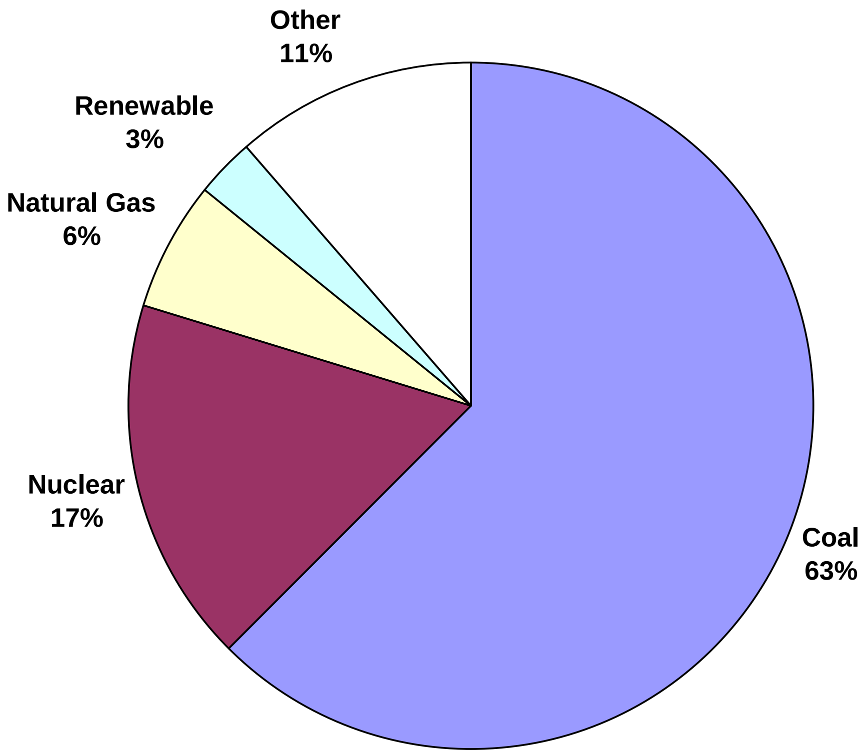
Figure 1-1 2005 Energy Production in Wisconsin – MWh



Note: "Other" is primarily imports. Data does not include transmission line losses.

Coal does have its costs, however, both to the environment and to public health. Coal-fired electricity production contributes to acid rain, haze, ground level ozone formation, and water quality degradation. Older coal plants, which burn pulverized coal in a boiler creating steam to turn a turbine, can be retrofitted with pollution control equipment. However, pollutants must be stripped from post-combustion gases. This is a difficult and expensive process. New super-critical pulverized coal (SCPC) designs are much more efficient at burning coal and therefore much cleaner for the environment. In contrast to these coal combustion designs, IGCC uses a gasification process prior to combustion that reduces coal into gases and residual solids under high heat and pressure. The resultant gases are more easily stripped of pollutants to form a cleaner burning "syngas" for use in the combustion stage.

Changing federal air policies have also served to heighten the interest in IGCC given its environmental promise. The U.S. Environmental Protection Agency (EPA) has adopted new rules that limit nitrogen oxide, sulfur dioxide and mercury emissions from electric generating units. It is anticipated that this will cause either significant expense to retrofit existing conventional coal plants with pollution control equipment or, if not cost effective, cause some older plants to be retired. Approximately 20 percent of Wisconsin's existing baseload coal generation capacity was built prior to 1960 and may fall into this second category.[9] Thus, the need for new baseload facilities with superior environmental performance has increased the interest in IGCC.

[9] Public Service Commission of Wisconsin. *2004 Strategic Energy Assessment.*

It is the prospect of controlling carbon dioxide emissions, however, that generates the most intense focus on IGCC. Carbon dioxide is the main greenhouse gas and is comparatively easier and less expensive to remove from an IGCC unit versus an SCPC unit; some estimate that carbon dioxide removal from SCPC will be twice as expensive as from IGCC.[10] Once captured, however, something must be done to store, or sequester, the carbon dioxide. Many avenues are being explored for this storage including depleted oil fields, deep coal seams, and saline reservoirs, but feasibility and transportation questions remain. If these carbon sequestration questions can be addressed, IGCC will have a significant environmental advantage over SCPC.

Although the U.S. does not currently regulate carbon dioxide emissions, there is much speculation that limits will be imposed in the near future. Senators Pete Domenici and Jeff Bingaman, Congressional leaders on energy policy, have developed a "white paper" on global warming issues in order to facilitate discussion and develop consensus for a specific bill.[11] In the House of Representatives this past March, U.S. Representatives Tom Udall and Tom Petri introduced the "Keep America Competitive Global Warming Policy Act of 2006," which places a limit on greenhouse gas emissions and uses a market-based approach to ensure compliance.[12] Among the broader public, interests as diverse as evangelical Christian leaders[13] and utility shareholders[14] have begun pushing for action to control greenhouse gas emissions. A backdrop to all of these developments is the international pressure created by the U.S.'s refusal to sign the Kyoto Protocol, an international treaty limiting greenhouse gas emissions.

The utility industry's operating experience with IGCC in the U.S. is limited, however. Currently, only two commercial-scale IGCC power plants are in operation in the U.S., the Wabash River Generating Station in Indiana and the Polk Power Station in Florida.[15] Significant concerns exist about both the cost and reliability of IGCC. In 2004, the National Association of Regulatory Utility Commissioners (NARUC) surveyed industry stakeholders to identify the institutional challenges inhibiting IGCC commercialization. The survey found that higher capital costs, questions about plant viability, uncertain up-front development costs, and low plant availability in the early years are viewed as the most significant barriers to IGCC deployment.[16] In the past few years, these barriers have proved difficult to overcome despite IGCC's environmental promise.

A further issue for Wisconsin is the fragmented nature of the electric industry in the state. Several of the nation's largest utility holding companies, including American Electric Power, the new Duke Energy (formed by the merger of Duke and Cinergy) and Southern Company, are pursuing IGCC projects. These are extremely large utilities that span several states with enterprise values in excess of $24.8 billion respectively.[17] In contrast, Wisconsin has five small to medium-sized investor-owned utilities operating in a state of 5.5 million people. The largest utility holding company in Wisconsin, Wisconsin Energy, has an enterprise value of $8.55 billion. Thus, absorbing the risk that IGCC presents is a bigger hurdle

[10] Standard and Poor's. "Prospects Improve for IGCC Technology in U.S., but Challenges Remain." August 25, 2005.

[11] Senators Pete Domenici and Jeff Bingaman. "Design Elements of a Mandatory Market-Based Greenhouse Gas Regulatory System." February 2006.

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[15] Internationally, electric generating IGCC plants exist in the Netherlands, Spain and Japan.

[16] National Association of Regulatory Utility Commissioners. *An Analysis of the Institutional Challenges to Commercialization and Deployment of IGCC Technology in the U.S. Electric Industry.* March 2004.

[17] Enterprise value is defined as market capitalization plus total debt less cash. Values as of May 16, 2006 from YAHOO! Finance.

for these small and medium-sized utilities.[18] A joint project may be an avenue to reducing the risk for any one Wisconsin utility.

Pursuing IGCC has thus become a question of timing: build now and risk reliability problems and higher construction costs as an early adopter or wait to learn from the experience of other projects and risk further environmental degradation and the prospect of relying on increasingly obsolete technology. This question is particularly timely for Wisconsin given its near-term building needs and the long lifespan of baseload plants. The state has a window in the next ten years in which major decisions will be made about energy infrastructure needs. Which alternatives are chosen will depend upon how much weight a decision-maker places on technological risk, cost considerations, environmental protection, potential changes in federal air policy, and financial alternatives. The remainder of this report attempts to shed light on how each of these areas impacts the choice of IGCC versus SCPC.

[18] As discussed elsewhere in the report, Xcel Energy, the holding company parent of NSP-Wisconsin, is pursuing an IGCC project through an affiliate in Colorado.

2

Chapter 2: Clean Coal Study Group

In August 2005, Governor Jim Doyle unveiled Conserve Wisconsin, a package of proposed legislation and executive orders to safeguard Wisconsin's environmental legacy. The agenda focuses on protecting waterways, conserving lands, revitalizing urban neighborhoods and promoting energy conservation and innovation.[19]

As a part of Conserve Wisconsin, Governor Doyle asked the Wisconsin Department of Natural Resources (DNR) and the Public Service Commission of Wisconsin (PSC) to investigate IGCC technology and its potential for the future of Wisconsin. DNR Air and Waste Administrator Al Shea and PSC Commissioner Mark Meyer led the Clean Coal Study Group. The goal of the group was to learn about IGCC technology, answer questions about reliability and cost, and advise the DNR and the PSC as this report developed. Study group members included electricity providers, environmental organizations, customer and labor groups, and research institutions.

To accomplish its objective, the Clean Coal Study Group developed guiding questions for six areas: engineering, cost, environmental, siting, economic development, and policy.

> **Engineering** – Is IGCC technology ready for commercial application? How do the operational characteristics and the construction timeframe of an IGCC plant compare to SCPC? How does coal type affect IGCC's operational characteristics? What are the opportunities and limitations for IGCC fuel options? How does Wisconsin's climate impact the operation of an IGCC plant? What design considerations are required for carbon capture?
>
> **Cost** – How do the economics and the ratepayer impacts of IGCC compare to SCPC, assuming a reasonable range of costs? What are the cost/benefit trade-offs, including carbon capture considerations? How do these trade-offs change if different assumptions are made about the cost of fuel or greenhouse gas emissions? Are there federal, including the Energy Policy Act of 2005, or other subsidies available for IGCC technology? What are the options for financing and ownership structure? How does the electric wholesale market impact the costs of IGCC? Are performance standards available for IGCC construction contracts?
>
> **Environmental** – How does the environmental impact, including air emissions, water use and solid waste, of IGCC compare to SCPC? How does the environmental regulatory climate, including the possibility for carbon emission limits, affect the choice of one over the other?

[19] Copies of the Conserve Wisconsin agenda can be found at: http://psc.wi.gov/CleanCoal/documents/ConserveWiBooklet.pdf.

Siting – Is Wisconsin a suitable host for IGCC? Do we have the resources in-state? Or have sufficient access to needed resources? What community impacts may be unique to IGCC?

Economic Development – How would IGCC affect the economic climate in Wisconsin? Does IGCC's co-production capability provide additional economic benefits?

Policy – Are there any barriers to permitting an IGCC unit in the state? What, if any, policy changes might be needed to permit an IGCC unit in Wisconsin? What can we learn from other states? Are there regulatory options for risk-sharing given that IGCC is a newer technology?

The Clean Coal Study Group met twice in the fall of 2005 and then monthly through the winter and spring of 2006. Meetings included presentations by industry experts, stakeholder discussions, and a tour of the Wabash River IGCC Generating Station, in West Terre Haute, Indiana.[20] A draft report was prepared by PSC and DNR staff and released for public comment in June 2006.

[20] All presentations to the IGCC Study Group referred to in this report can be found at: http://psc.wi.gov/cleancoal/meetings.htm.

3

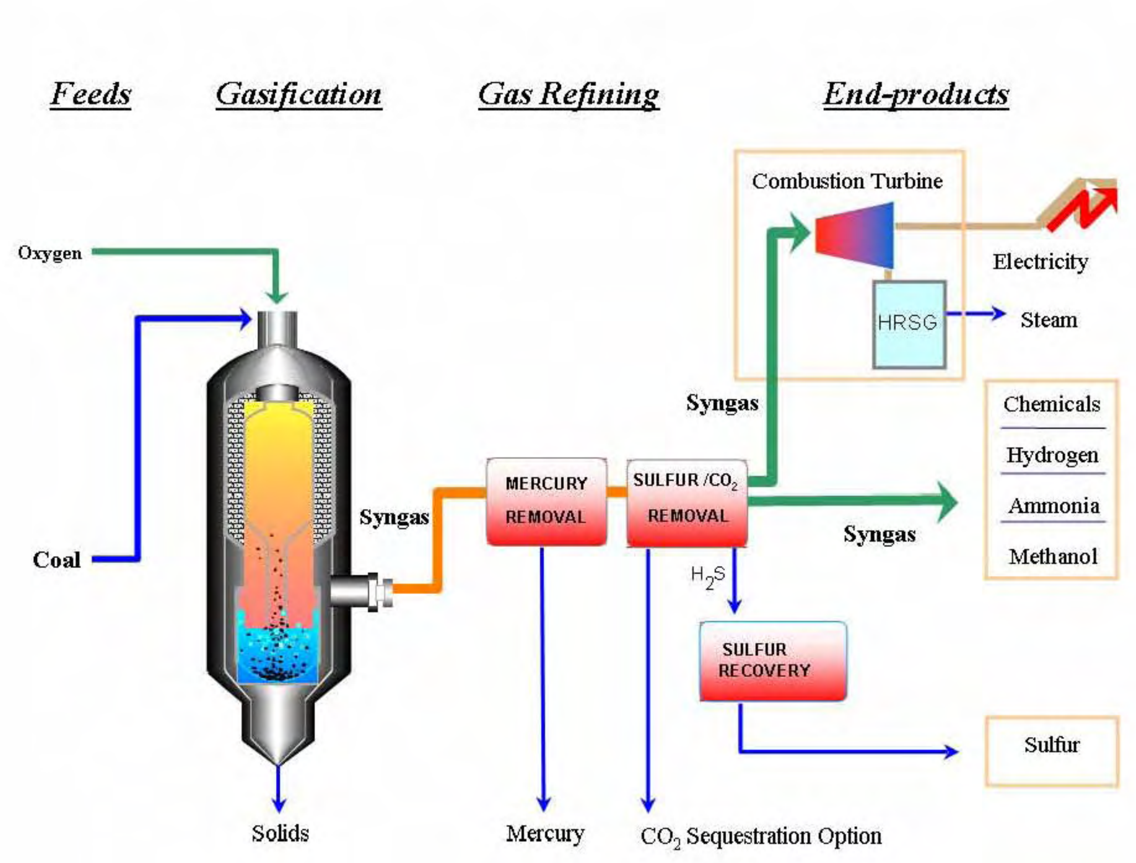
Chapter 3: Engineering

TECHNOLOGY

IGCC power plants use a combined-cycle design incorporating both gas and steam turbines to maximize the benefits of coal gasification. Coal gasification is a process by which coal, under high pressure and temperature, is broken down into gases prior to combustion. The resultant synthetic gas is a mixture of carbon monoxide, hydrogen, and methane that can be used as fuel for electricity generation. The synthetic natural gas, commonly called syngas, can also be used for injection into the gas pipeline system, or as raw materials for chemical manufacture.

There are five IGCC plants now in operation. Two are located in the U.S., two in Europe, and one in Japan. A simple diagram of IGCC is illustrated in the figure below.

Figure 3-1 IGCC Schematic



Source: Clean Air Task Force

Description of the IGCC Generation Process

Rather than burning coal in a boiler to generate steam, coal gasification chemically breaks apart coal in a gasifier and then uses a combined-cycle design, common to natural gas plants, to generate electricity. There are three different types of gasifiers that vary by how heat is added. The type of fuel and desired product (e.g. electricity, syngas, or chemicals) influences the type of gasifier selected.

During the gasification stage, coal reacts with oxygen, and frequently with steam, to produce syngas. Oxygen obtained from an air separation unit built as part of the IGCC unit is required to carefully control chemical reactions. These reactions generate additional heat and produce gas. Under high heat and pressure, the coal is transformed into gases, primarily carbon monoxide and hydrogen with smaller amounts of methane. Syngas, additional steam, and slag, a solid waste that can be used as an alternative for sand or gravel, are the results of this stage. An additional stack is also necessary to flare unsuitable gas created during unit start-up or when the unit trips out of service.

During the refining stage, the syngas is cleaned to remove pollutants. Sulfur is removed with acid gas removal equipment and can be recovered as elemental sulfur or sulfuric acid for resale. Mercury and carbon dioxide can also be filtered out at this stage. IGCC has superior environmental performance because these pollutants can be removed prior to combustion in higher concentrations than post-combustion exhaust gas in an SCPC unit.

Once cleaned, the syngas can then be used to generate electricity using a combined-cycle design. The syngas is delivered to a gas turbine while the residual steam from the gasification process is captured in a heat recovery steam generator and used to drive a second turbine. This portion of the facility is similar to the many combined-cycle natural gas plants that have been built worldwide in the last 15 years.

Carbon Dioxide Capture

Although no IGCC plants currently employ carbon dioxide capture technology, it is anticipated that it will be incorporated in future IGCC designs. However, because it is not used in practice today, it is uncertain how carbon capture will impact the overall plant design.

Most likely, carbon dioxide would be removed using a phase shifter to convert carbon monoxide gas to carbon dioxide at the end of the gas refining stage. A phase shifter could be designed to capture the majority of carbon dioxide, which would result in a syngas of almost pure hydrogen. Since it alters the composition of the syngas, this change may require a new combustion turbine designed for hydrogen operation. The phase shifter would also produce heat in the gas transformation process that could be used to generate additional steam to drive the steam turbine cycle. Several of the proposed plants discussed in the following section are investigating the possibility of carbon dioxide capture.

Power the Future Application and Industry Developments

Wisconsin first reviewed IGCC technology during We Energies' Power the Future project. This was one of the first IGCC applications to come before a state commission in over a decade. In January 2002, We Energies applied for construction authority to build two 600 MW SCPC units and one 600 MW IGCC unit, targeting commercial operation for all three units by 2011. In November 2003, the Commission issued its decision, approving the two SCPC units and rejecting the IGCC unit. In denying the IGCC application, the Commission found that IGCC was not a reasonable alternative at the time because of its higher construction cost, inferior efficiency rate, and immature technology.[21]

Since that decision, the industry has developed such that IGCC may be more attractive today. Gasification vendors such as GE Energy and ConocoPhillips have partnered with architectural and engineering firms such as Bechtel Corporation and Fluor Corporation. These alliances provide a "one-stop-shop" for utilities offering both technology and construction expertise in one package. Additionally, these partnerships are beginning to offer a project "wrap" that includes a firm price for engineering, procurement and construction, and guarantees the construction schedule, plant output, heat rate and air emissions.[22] These project wraps are expected to reduce the technological risk of IGCC and standardize the upfront construction costs, two significant variables that caused the Commission to reject IGCC in 2003.

EXISTING IGCC FACILITIES

There are five electric generating IGCC plants now in operation. Two are located in the U.S., two in Europe, and one in Japan. A brief description of each follows.

[21] PSC Final Decision in the Application of Wisconsin Electric Power Company to Construct the Elm Road Generating Facilities. Docket 05-CE-130. November 10, 2003.
[22] Presentation by Norman Shilling, GE Energy, and Lee Schmoe, Bechtel Corporation, to IGCC Study Group, Dec. 2, 2005.

ConocoPhillips and Cinergy jointly operate the Wabash River Generating Station (see Figure 3-2) in West Terre Haute, Indiana. The Wabash River facility is a repowering of an existing coal plant with 262 MW of capacity. It became operational in 1995 and was a U.S. Department of Energy (DOE) demonstration project, receiving 50 percent of the total project funding from DOE during a four-year demonstration phase.[23] The plant now operates as a baseload unit in Cinergy's generation fleet.

Figure 3-2 Wabash River Generating Station in Indiana

[23] Research Reports International. *Coal Gasification for Power Generation.* September 2005, pg. 106.

The Polk Power Station (see Figure 3-3) is an IGCC facility run by Tampa Electric Company in southern Florida. The plant has 250 MW of capacity and was also a part of the DOE's demonstration program, receiving $120 million in federal funds.[24] The project was placed in commercial operation in 1996 and continues to operate commercially for Tampa Electric Company today.

Figure 3-3 Polk Power Plant in Florida

The first European IGCC plant was the NUON project in Buggenum, the Netherlands. The plant has 253 MW of capacity and operated as a demonstration project for its first four years. It was placed in commercial operation in 1998. More recently, as European nations try to reduce carbon dioxide emissions, this plant has been experimenting with biomass feedstock, partially replacing coal. Initial tests have been successful.

The second European project, the ELCOGAS project in Puertollano, Spain, was launched as a consortium of eight European utilities and three technology suppliers to demonstrate the commercial feasibility of IGCC. The plant has 298 MW of capacity and was placed in operation in early 1998.

Japan is also testing the feasibility of IGCC with an added component of fuel cell technology. J Power developed the EAGLE plant, which utilizes integrated coal gasification fuel cell combined-cycle

[24] Research Reports International. *Coal Gasification for Power Generation.* September 2005, pg. 104.

technology to test the increase in IGCC efficiency with the inclusion of fuel cells. The plant was placed in operation in 2002 for a test period of five years with a total budget of $211 million.[25]

PROPOSED U.S. IGCC FACILITIES

Recently, several U.S. utilities and merchant power producers have announced plans for IGCC plants, including American Electric Power, BP and Edison Mission Group, Cinergy, the Erora Group, Excelsior Energy, Southern Company, Steelhead Energy, and Xcel Energy. Each project is described briefly below. Dozens of IGCC projects have also been proposed in Europe and Asia.

American Electric Power: AEP, one of the nation's largest electricity providers, is developing plans for three 600 MW IGCC projects – one each in Ohio, West Virginia, and Kentucky. The projects are in development with the first targeted to be operational by 2010; the plants are expected to utilize regional coal.

On January 11, 2006, Appalachian Power Company filed an application with the West Virginia Commission to construct a 600 MW IGCC project planned to be located at its Mountaineer Station plant in Mason County.[26] In addition, on March 24, 2006, Columbus Southern Power Company and Ohio Power Company filed a joint application with the Ohio Commission to construct a 629 MW Great Bend IGCC Project to be built in Meigs County, Ohio.[27] A third potential site has been identified in Lewis County, Kentucky.

The Ohio Commission recently ruled that AEP Ohio is entitled to recover pre-construction costs for the Ohio project from customers and that it is reasonable to recover project costs through a provider of last resort recovery mechanism.[28] Achieving this guarantee of cost recovery was an important step for AEP to proceed with the project.

BP and Edison Mission Group: BP and the Edison Mission Group announced plans in February 2006 for a new 500 MW $1 billion hydrogen-fueled power plant that will rely on the gasification process. To be located south of Los Angeles, the project will generate electricity using petroleum coke and will capture carbon dioxide for sequestration in California's oil fields. The proposed gasification facility has the potential to be the first IGCC electric generating plant with carbon dioxide sequestration and will rely, in part, on funds from the federal Energy Policy Act of 2005.

Cinergy:[29] This company is studying the feasibility of constructing an IGCC plant to be owned and operated by its utility subsidiary, Public Service of Indiana (PSI). In August 2005, PSI and Vectren Energy Delivery of Indiana, Inc. filed a joint petition at the Indiana Commission seeking cost recovery of a feasibility study as well as engineering and preconstruction costs. A decision has not yet been made by the Indiana Commission, and the company has not yet filed an application to build the plant.

Erora Group: The Erora Group has proposed a merchant IGCC power plant, the Taylorville Energy Center, in Christian County in south central Illinois. The proposed minemouth facility would use

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[25] Research Reports International. *Coal Gasification for Power Generation.* September 2005, pg. 114.
[26] The case number assigned to the application is 06-0033-E-CN
[27] The case number assigned to the application is 06-30-EL-BGN.
[28] AEP Ohio press release. "AEP Ohio Receives Approval to Recover IGCC Pre-Construction Costs." April 10, 2006.
[29] Effective April 3, 2006, Cinergy merged with Duke Energy, with the surviving entity retaining the name Duke Energy.

Illinois basin bituminous coal to fuel two gasifiers feeding a 770 MW combined-cycle generating facility. The facility is being designed so that one gasifier can be switched to produce synthetic natural gas. To meet sulfur requirements for synthetic natural gas, the facility is proposing to use a solvent, Selexol, to enhance sulfur removal. The additional sulfur removal enables the use of selective catalytic reduction, which is expected to further reduce nitrogen oxide emissions. The project is anticipated to be placed in commercial operation in 2010.

Excelsior Energy: Excelsior Energy is a merchant power producer with the sole purpose of developing the Mesaba Energy project in northern Minnesota. The Mesaba Project includes plans to develop two 600 MW IGCC plants with the flexibility to burn both western and eastern coal. Carbon capture technology is not anticipated in the initial phase of the project. The in-service date for the first unit is targeted for 2011. The project received considerable support from enabling state legislation, including an exemption from the construction permitting process and an entitlement to a purchase power agreement with Xcel Energy. Excelsior Energy recently filed an application for approval of this agreement with the Minnesota Commission.

Southern Company: Southern Company recently signed an agreement with DOE to build a 285 MW project near Orlando, Florida. The project is estimated to cost $557 million, with DOE contributing $235 million.[30] The project is anticipated to be placed in commercial operation in 2010 and is expected to be able to handle western coal.

Illinois Steelhead Energy: Steelhead Energy, also a merchant enterprise, recently received a small grant from the state of Illinois for the development of a 545 MW IGCC plant. The plant is conceived for southern Illinois, adjacent to a coal mine, and will burn Illinois coal. The project will be designed to integrate electric power production with the production of synthetic natural gas.

Xcel Energy: Xcel Energy is proceeding with plans for a 300 MW demonstration plant using western coal and some level of carbon dioxide capture. Xcel is pursuing federal funds for the project under the Energy Policy Act of 2005 and state legislation to guarantee full cost recovery and provide development funds. The project is targeted for operation by 2012 or 2013.[31]

FutureGen

FutureGen is an initiative sponsored by DOE to produce a 275 MW zero emission IGCC plant with carbon sequestration. A public-private alliance has been formed to oversee the project, including the DOE and other government entities, coal producers and electric utilities. The project is in the early stages of design, and a competitive site selection process is underway. Several states including Texas, Illinois, Wyoming and Montana are expected to bid for the project. Initial operations are estimated for 2012.[32]

[30] Southern Company press release. "New Clean Coal Technology Plant Reaches Milestone with Formal Signing of Agreement." February 22, 2006.
[31] Presentation by Frank Prager, Xcel Energy, to the IGCC Study Group, March 10, 2006.
[32] For more information, see: http://www.fossil.energy.gov/programs/powersystems/futuregen/

4

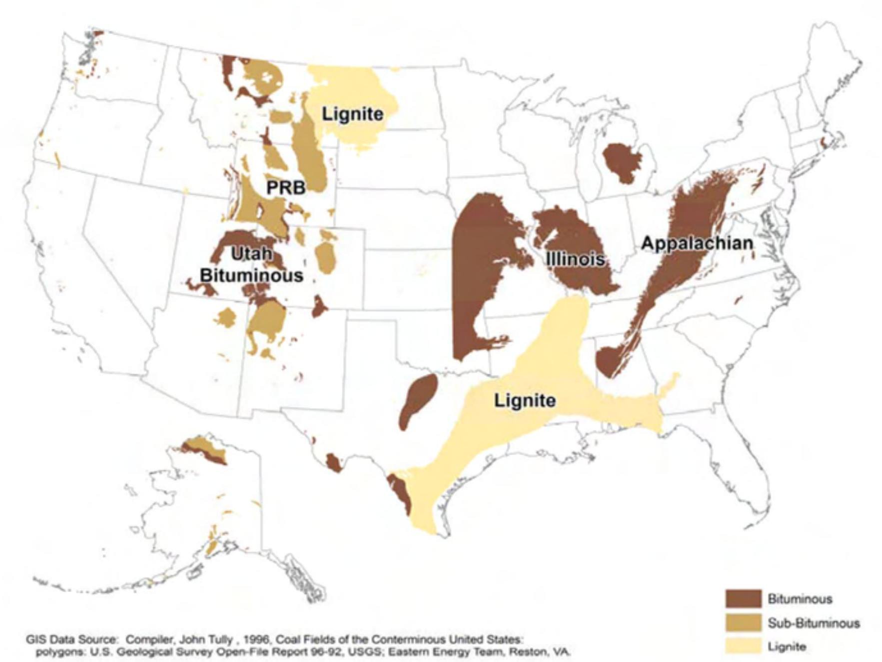
Chapter 4: Cost

DESCRIPTION OF COST ANALYSIS

A hypothetical cost model was developed to compare the costs of IGCC and SCPC. The analysis compares a 600 MW SCPC plant with a 600 MW IGCC plant, fired by either eastern (bituminous) or western (sub-bituminous) coal.[33] While approximately 95 percent of the coal consumed for power generation in Wisconsin is western coal,[34] the IGCC plants in operation in the U.S. today rely on eastern coal and petroleum coke (although both Xcel Energy and Excelsior Energy are pursuing IGCC projects using western coal). Both coal types are common for coal-fired generation, so both cases are included in the analysis.

The analysis is a "screening cost" analysis, which is best used to compare costs among technologies. The results of the analysis are illustrative and not predictive of future costs; model assumptions are described in detail at the end of this chapter. A future project seeking construction approval would require a much more detailed cost review.

Figure 4-1 U.S. Coal Reserves

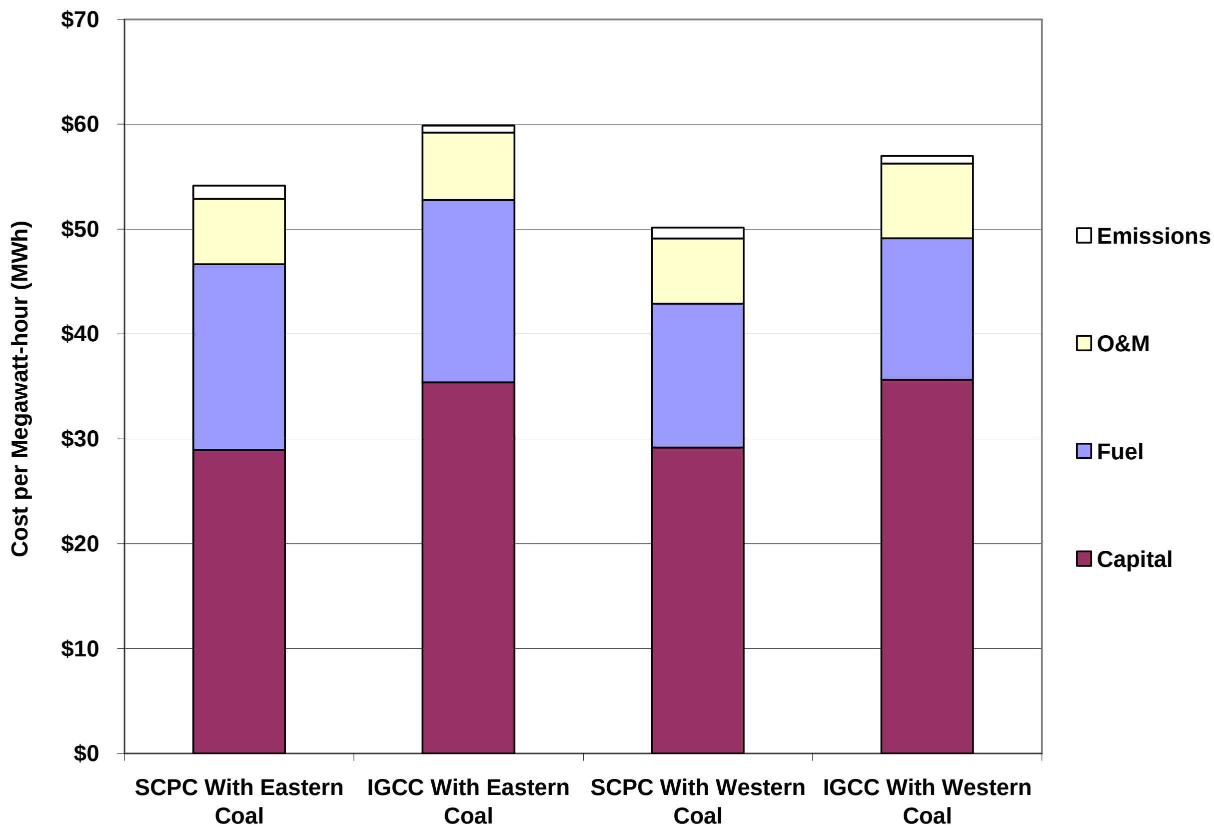


[33] The focus is on new facilities to prevent vintaging problems associated with comparing older facilities with the newer IGCC technology.
[34] Department of Administration. 2005 Wisconsin Energy Statistics.

MODEL RESULTS

The results of the analysis show that the cost for IGCC with eastern coal is about $5 higher per MWh of energy generated than SCPC, and for IGCC with western coal, about $7 higher. Figure 4-2 illustrates the differences in the major cost categories. The major drivers behind the cost premium for IGCC are construction costs, reliability of operations, and plant efficiency. Each issue is addressed below.

Figure 4-2 SCPC and IGCC Final Production Cost Comparison ($/MWh)



Construction cost is a major factor causing the increased cost for IGCC. It is generally perceived in the industry, even by the vendors who make the gasification units, that IGCC will have a construction cost premium over SCPC. This is largely due to the newer technology and the lack of "off-the-shelf" engineering. Industry estimates suggest a 10 to 20 percent premium.[35] This analysis assumes 15 percent. However, this premium will likely decrease as the industry gains more experience with IGCC. A 5 percent change in the construction cost of IGCC with eastern coal improves the final production cost difference by approximately $1.50/MWh. Construction cost, therefore, is a major factor driving up the cost of IGCC.

Reliability is another major driver behind the cost premium for IGCC. In the cost analysis, reliability is expressed as the capacity factor, or the ratio of the plant's output to what it could have produced had it run 100 percent of the time at its full capacity. Baseload units, typically coal or nuclear, generally have capacity factors in the range of 85 percent.

[35] Presentation by Norman Shilling, GE Energy, to IGCC Study Group, December 2, 2005.

The two IGCC plants operating in the U.S. had considerable reliability problems in the early years, resulting in low capacity factors. These two plants are now demonstrating reliability close to conventional coal units. However, considerable concern remains in the industry that future IGCC plants will not be able to match the reliability of SCPC, given the history of the early IGCC units. A 5 percent change in the capacity factor for IGCC with eastern coal causes approximately a $2.50/MWh change in the final production cost for IGCC. Reliability, therefore, is another major factor driving the costs for IGCC.

The emerging trend of construction and performance guarantees for IGCC may help to reduce this reliability risk. GE Energy, a major manufacturer of gasification units, and Bechtel Corporation, an architectural and engineering firm, are offering project "wraps" that include a firm price for engineering, procurement and construction, and guaranteeing the construction schedule, plant output, heat rate and air emissions.[36] GE Energy indicates these guarantees will help minimize the risk of IGCC and assist with financing costs. Other industry partnerships are expected to follow suit with similar performance guarantees. Although these performance guarantees will reduce the reliability risk, they may increase the contract price and, therefore, the overall construction cost of IGCC.

A related issue to reliability is the durability of the plant, or the plant's operating life. Generally, 30 years is the accounting assumption for plant operating life, even though coal plants often continue to operate decades beyond this. Given IGCC's limited operating history, however, operating life for IGCC is uncertain. Reducing the lifespan of IGCC with eastern coal by five years, to 25 years, changes the final production cost of electricity by a little over $1/MWh.

The estimated efficiency of a plant is another major driver in the final production cost of electricity. Efficiency estimates the rate at which a plant converts the energy value of its fuel into electricity. It is also expressed as the plant's heat rate and varies by the age, design, and type of fuel utilized at each plant. The higher the efficiency, the more economical it becomes to produce electricity. In this cost analysis, a 2 percent gain in efficiency for IGCC with eastern coal results in about a $1/MWh decrease in the final production cost of electricity. Because IGCC is a relatively new technology, its rate of improvement (*e.g.* gains in efficiency) is expected to outpace SCPC, which has been in use for decades.[37] Thus, IGCC may have more promise to make efficiency gains.

Efficiency is also important because it is closely tied to the amount of pollution emitted by a plant. With higher efficiency, less coal is needed to produce the same amount of electricity, and less pollutants are produced. A lump of coal has the same carbon dioxide polluting potential whether it is burned in an IGCC or SCPC unit, assuming it is burned in equivalent amounts. Should IGCC achieve the anticipated efficiency gains, it will burn less coal and less pollutants will be produced. This is particularly critical when considering the possibility of carbon dioxide emission limits. Air emissions generally, and the treatment of carbon dioxide specifically, is explored in depth in Chapter 5.

Model Results with Favorable Operating Conditions

As discussed above, construction costs, reliability and efficiency are the three major operating variables that drive the final production cost of electricity from an IGCC unit. Changes to these variables significantly alter the cost comparison with SCPC. Because IGCC technology is still under development, these factors are estimates with a range of uncertainty.

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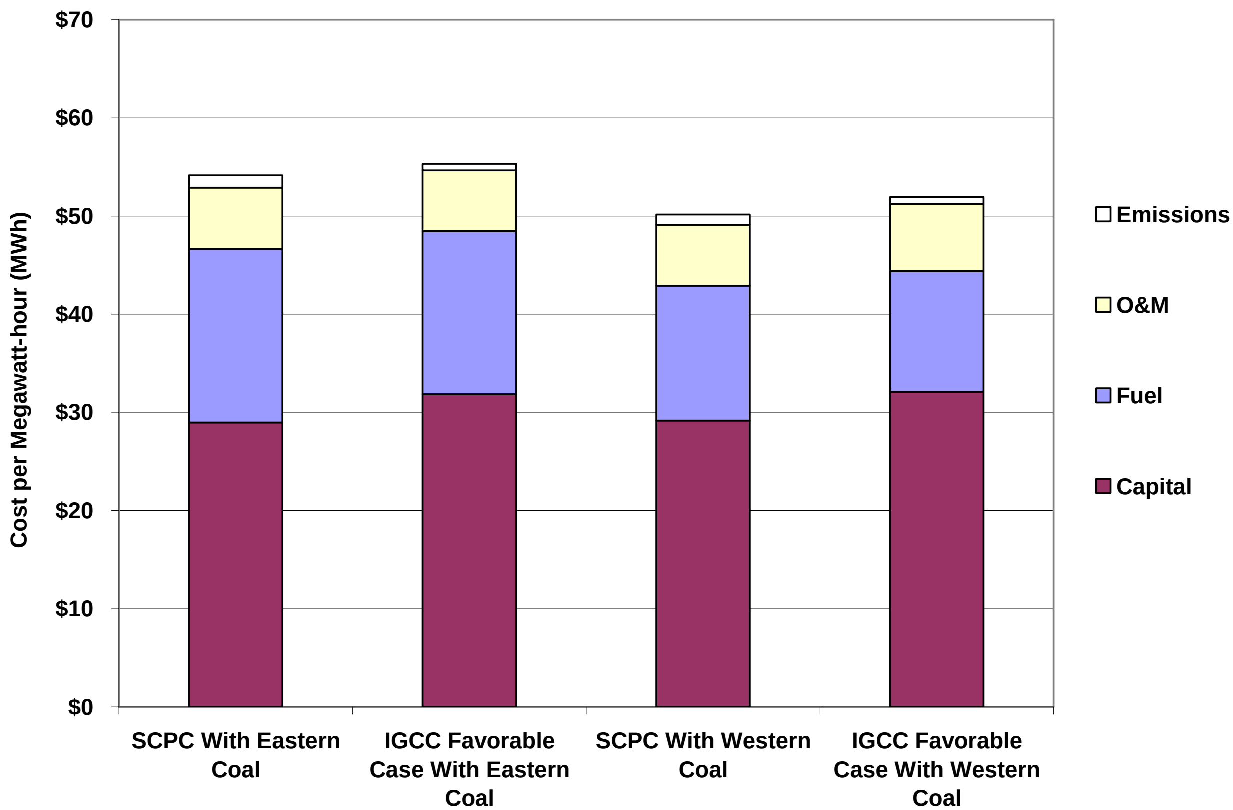
[36] Presentation by Norman Shilling, GE Energy, and Lee Schmoe, Bechtel Corporation, to IGCC Study Group, December. 2, 2005.

[37] See Appendix A for a partial list of SCPC units in operation in the U.S.

The figure below assumes more favorable operating conditions for IGCC – the construction cost premium is reduced to 10 percent, the capacity factor is increased by 5 percent, putting it on par with the assumption for SCPC, and the efficiency is increased by a little less than 2 percent. Under these favorable conditions, the final production cost for IGCC with eastern coal is about $1.25 more per MWh than SCPC, before accounting for the treatment of carbon dioxide. While this puts IGCC in range of SCPC, this is an optimistic scenario assuming favorable conditions for all three key operating factors.

Figure 4-3 Cost Comparison with Favorable IGCC Operating Conditions ($/MWh)



Midwest Independent Transmission System Operator

Operating an IGCC unit in the wholesale electricity market overseen by the Midwest Independent Transmission System Operator, Inc. (MISO) was also considered in the analysis. As IGCC may have slightly longer startup and turn-down times than an SCPC unit, this must be taken into consideration when describing the plant's characteristics for MISO. Otherwise, there are no unique operational barriers to IGCC functioning in the MISO market. It is expected that IGCC would act as a baseload unit and be called upon for electricity production before an intermediate or peaker plant.

MODEL INPUTS

Figure 4-4 depicts the assumptions that were used to develop the cost model. In general, data from the We Energies' Elm Road Generating Station and Wisconsin Public Service Corporation's Weston 4 power plant were used for SCPC, and technical sources were used for the IGCC cases. The remainder of this chapter discusses these inputs in detail.

Figure 4-4 Cost Model Assumptions

	SCPC With Eastern Coal	IGCC With Eastern Coal	SCPC With Western Coal	IGCC With Western Coal
Engineering Parameters				
Rating (kW)	600,000	600,000	600,000	600,000
Capacity Factor	85.0%	80.0%	85.0%	80.0%
Capital Costs				
Construction Cost ($/kW)	$1,628	$1,872	$1,639	$1,885
Economic Cost of Capital at 11.0% ROE	12.90%	12.90%	12.90%	12.90%
Operating Life (Years)	30	30	30	30
Fuel Costs				
Heat Rate (BTU/kWh)	8,850	8,700	9,150	9,000
Efficiency	38.6%	39.2%	37.3%	37.9%
Fuel Heating Value (BTU/lb)	10,200	10,200	8,700	8,700
Average Price($/MMBTU)	$2.00	$2.00	$1.50	$1.50
O&M Costs				
Fixed Operating Costs ($/kW/Yr)	$24.00	$34.21	$24.00	$34.21
Variable O&M Costs ($/MWh)	$3.00	$2.58	$3.00	$2.58
Emission Rates (LB/MWh)				
NO_x	0.62	0.51	0.55	0.53
SO_2	1.33	0.29	0.82	0.30
Hg	9.91E-06	4.90E-06	1.56E-05	6.40E-06
CO_2	1,831	1,800	1,960	1,928
Emission Costs ($/Ton)				
NO_x	$2,000	$2,000	$2,000	$2,000
SO_2	$800	$800	$800	$800
Hg	$20,000,000	$20,000,000	$20,000,000	$20,000,000

The capacity factor is the percentage of time a unit produces electricity after accounting for outages, both planned (planned maintenance) and unplanned (forced outage rate), and start-up and turn-down times. Baseload units, typically coal or nuclear plants, are run most often due to their cost-effectiveness and, therefore, have the highest capacity factors. An 85 percent capacity factor is assumed for the SCPC cases in the cost comparison based on estimates of what a new SCPC unit will likely achieve.[38] Availability is the time the plant is guaranteed not to be forced out of service. Availability figures are sometimes provided for sections of plants as well and are not the same as total plant availability.

Determining a capacity factor for an IGCC plant turns on the question of the reliability of the technology. Availability data for the Wabash River Generating Station and Polk Power Station, the two

[38] Based on PSC analysis from Wisconsin Electric Corporation's Elm Road Application (docket 05-CE-130) and Wisconsin Public Service Corporation's Weston 4 Application (docket 6690-CE-187).

IGCC plants in commercial operation in the U.S., and the two European IGCC units ranges from 80 to 90 percent.[39] This analysis assumes an 80 percent capacity factor, with sensitivities at 75 to 85 percent.

Another issue impacting IGCC's capacity factor is its extended start-up and turn-down times. Generally, IGCC is expected to have longer ramp periods than SCPC due to the air separation unit. This difference also contributes to the slightly lower capacity factor for IGCC as compared to SCPC.

Another input is the assumed operating life of each unit. In this analysis, a 30-year life is assumed for all cases. While in practice, coal plants often are in operation a decade or two longer than this, 30 years is the industry rule of thumb for plant book life. A sensitivity with a shorter operating life for IGCC was also run and is discussed in the results section of this chapter.

Capital Costs

Although there are numerous projects under development, an IGCC plant has not been built in the U.S. for over a decade. Given the numerous design changes and technological advances in IGCC since that time, construction cost data for an IGCC plant is difficult to ascertain. Industry estimates indicate IGCC has a 10 to 20 percent higher capital cost than an SCPC plant.[40] For purposes of this analysis, a 15 percent cost premium is assumed with an in-service date of 2012-2015. As actual IGCC projects develop, firmer construction cost information should become available. Sensitivities were also run to estimate higher (20 percent) and lower (10 percent) capital costs.

For reliability reasons, a spare gasifier is often considered in the design of an IGCC plant. Wabash River currently relies on a spare gasifier; the Mesaba project intends to,[41] and American Electric Power (AEP) is considering it.[42] A decision to include a spare gasifier increases the capital costs for an IGCC plant, to the magnitude of $50 to $75 million, but will have the benefit of increasing the plant's capacity factor.[43] In this analysis, it is assumed that a spare gasifier is included in the 15 percent cost premium.

For the SCPC units, construction costs from the Elm Road Generating Station, using eastern coal, and the Weston 4 Power Plant, using western coal, were used as a starting point. Adjustments were made to these numbers to account for changes in construction costs since the projects were approved and the treatment of common facility costs. The costs were also scaled to a 600 MW capacity rating. A capital cost of $1,628/kW[44] and $1,639/kW[45] respectively are assumed; this excludes escalation and carrying costs.

Another component used to estimate capital costs is the economic cost of capital. This is the weighted cost of capital, including equity and debt, after accounting for taxes. While the debt rate is relatively easy to ascertain, the return on equity has varied over time. In recent rate decisions, the Commission has granted returns on equity in the range of 11.0 to 11.5 percent. For purposes of this analysis, an 11.0 percent return on equity is assumed for all cases, which results in a 12.9 percent economic cost of capital. A sensitivity altering the weighted cost of capital for an IGCC unit was run; it showed

[39] Holt, N. "Coal-based IGCC Plants – Recent Operating Experience and Lessons Learned." Gasification Technologies Conference. October 2004.

[40] Presentation by Norman Shilling, GE Energy, to IGCC Study Group, December 2, 2005.

[41] Presentation by Tom Micheletti, Excelsior Energy, to IGCC Study Group, Feb. 10, 2006.

[42] AEP White Paper. "Integrated Gasification Combined Cycle Technology." May 5, 2005, pg. 9.

[43] AEP White Paper. "Integrated Gasification Combined Cycle Technology." May 5, 2005, pg. 9.

[44] Elm Road Generating Station. Final Environmental Impact Statement. Docket No. 05-CE-130. July 2003, Vol. 1, pg. 12.

[45] Weston 4. Final Environmental Impact Statement. Docket No. 6690-CE-187. July 2004, Vol. 1, pg. 44.

significant impact on the final cost of electricity from the plant. This and other financing alternatives are discussed in more depth in Chapter 7.

Fuel Costs

Efficiency estimates the rate at which a plant converts the energy value of its fuel into electricity; it is also expressed as the plant's heat rate and varies by the age, design, and type of fuel utilized at each plant. The higher the efficiency, the more economical it becomes to produce electricity. Conventional coal plants generally reach 30 to 40 percent efficiency values, and natural gas combined-cycle can achieve up to 50 percent efficiency.

It should be noted that the Wabash River and Polk plants burn petroleum coke, a refinery byproduct, along with eastern coal. Petroleum coke has been a problematic fuel due, in part, to its extremely high sulfur content even though it has a very high energy content (British thermal units per ton). It has been a good fuel match for these two IGCC units as the gasification process has an inherent engineering advantage in removing sulfur from the fuel prior to combustion.

Figure 4-5 illustrates the range of efficiencies anticipated for SCPC and IGCC projects using eastern coal, and Figure 4-6 illustrates the range anticipated for projects using western coal.

Figure 4-5 Anticipated Heat Rates for Units Using Eastern Coal

	Source	Heat Rate (Btu/kWh)	Efficiency (%)
SCPC w/eastern coal	Energy Information Administration[46]	8,844	38.6%
	Electric Power Research Institute[47]	8,800	38.8%
	We Energies – Elm Road Application[48]	8,850	38.6%
IGCC w/eastern coal	Energy Information Administration[49]	8,309	41.1%
	Electric Power Research Institute[50]	8,300	41.1%
	AEP Application[51]	8,700	39.2%
	Wabash Plant[52]	8,900	38.3%
	Polk Plant[53]	9,200	37.1%

Due to its higher moisture content, western coal requires more heat to convert energy into electricity. Thus, coal plants fired with western coal have higher heat rates and lower efficiencies, independent of the type of firing technology. Figure 4-6 illustrates the range of efficiencies anticipated for SCPC and IGCC projects using western coal.

[46] Data did not differentiate between eastern versus western coal. Energy Information Administration. 2004 Annual Energy Outlook.
[47] EPRI estimate from internal reports.
[48] Elm Road Generating Station. Final Environmental Impact Statement. July 2003, Vol. 1, pg. 105. Percentage is the mid-range used in the PSC's analysis of the application.
[49] Energy Information Administration. 2004 Annual Energy Outlook.
[50] Presentation by Stuart Dalton, EPRI, to IGCC Study Group, Dec. 2, 2005.
[51] AEP White Paper. "Integrated Gasification Combined Cycle Technology." May 5, 2005, pg. 35.
[52] Presentation by Tom Lynch, ConocoPhillips, to IGCC Study Group, Jan. 13, 2006. Burns a mixture of Illinois coal and pet coke.
[53] Discussion with John McDaniel, TECO, on April 3, 2006. Burns a mixture of eastern coal and pet cokc.

Figure 4-6 Anticipated Heat Rates for Units Using Western Coal

	Source	Heat Rate (Btu/kWh)	Efficiency (%)
SCPC w/western coal	Electric Power Research Institute[54]	9,200	37.1%
	WI Public Service - Weston 4 Application[55]	9,150	37.3%
IGCC w/western coal	Electric Power Research Institute[56]	8,890	38.4%
	Mesaba Application[57]	9,391	36.3%

These figures demonstrate that there is a considerable range of anticipated efficiencies for IGCC. Using estimates from the AEP application and Electric Power Research Institute, this analysis assumed 39.2 percent efficiency for IGCC with eastern coal and 37.9 percent efficiency for IGCC with western coal. The SCPC values were taken from the We Energies and Wisconsin Public Service applications.

The actual price of the fuel commodity is another significant factor in determining the final production cost of electricity. The volatility of natural gas prices has been well documented in the media as of late, and the Commission has taken several steps to protect Wisconsin consumers. For IGCC and SCPC, however, assuming similar efficiencies, fuel costs are not a distinguishing factor. For purposes of this analysis, the cost of eastern coal with rail transport is assumed at $2.00/million Btu (mmBtu) and for western coal at $1.50/mmBtu.[58]

There are several fuel related issues that could impact the cost to produce electricity from coal-fired units. Train derailment and rail maintenance issues have hindered delivery of coal from Wyoming over the past year, and utilities are increasingly concerned about rail transport costs. The Commission has opened an investigation to look into these costs (docket 5-UI-110) but, as stated above, these will equally impact SCPC and IGCC assuming the same operational efficiencies.

Operation and Maintenance Costs

Fixed and variable operation and maintenance (O&M) costs did not have a significant impact on the cost comparison results. For purposes of consistency, the Energy Information Administration data was used for both IGCC cases, estimating fixed O&M costs at $34.21/kW per year and variable O&M at $2.58/MWh.[59] Given the lack of IGCC operational history, however, there is considerable uncertainty in these estimates. SCPC fixed O&M costs were $24.00/kW per year and variable costs were $3.00/MWh based on information supplied in the Weston 4 and Elm Road applications. Although sensitivities were run adjusting these values for IGCC, they had little impact on the final production cost of electricity.

IGCC does produce some salable by-products that can help offset the O&M cost. Sulfur can be extracted during the gasification process and sold either in its elemental form or as sulfuric acid. For purposes of this analysis, it is assumed that an IGCC plant with eastern coal has the potential to produce

[54] EPRI estimate from internal reports.
[55] Weston 4. Final Environmental Impact Statement. July 2004, Vol. 1, pg. 23.
[56] Presentation by Stuart Dalton, EPRI, to IGCC Study Group, Dec. 2, 2005.
[57] Excelsior Energy Petition for Approval of a Purchase Power Agreement to the Minnesota Public Utilities Commission. Docket No. E6472/M-05-1993. December 2005. Sec. IV, pg. 100.
[58] Energy Information Administration. January 2006 Electric Power Monthly.
[59] Energy Information Administration. 2004 Annual Energy Outlook.

over $4 million in sulfuric acid per year, and a western coal-fired IGCC plant has the potential to produce over $1 million. The value of sulfur is estimated at $40 per ton, and sensitivities were also included for values at $25 and $50 per ton with little overall effect. An SCPC plant does not produce a similar sulfur by-product.

A second issue related to by-products is solid waste production. Both IGCC and SCPC produce solid waste that can be used in road beds and construction fill. IGCC produces an inert glassy slag, and SCPC produces bottom ash. This analysis assumes slag and bottom ash are produced, but there is no additional value of one over the other.

Lastly, SCPC also produces fly ash, which can have a positive or negative impact on the plant's operating expenses depending on the type of desulfurization process used. With the right technology, fly ash could be collected along with gypsum and used to produce wallboard, or it will need to be disposed of with associated collection and disposal costs. For purposes of this analysis, the production of fly ash is assumed to be revenue neutral.

Emissions

A thorough discussion of air issues is addressed in Chapter 5. Emission levels for both IGCC and SCPC were based on the EPA's working national database of new plants with proposed or approved new source permits.[60]

Emissions of nitrogen oxide, sulfur dioxide and mercury were "monetized" in the analysis by multiplying the annual expected emission rates with current market prices for these pollutants. This offers a rough yardstick by which to compare the market-based emission costs of SCPC and IGCC. Values for these three emissions were estimated from Platts news service.[61]

Although the base cases in the analysis do not monetize carbon dioxide emissions, a sensitivity was run to gauge the impact of potential future carbon dioxide restrictions. Since a market does not currently exist in the U.S. for carbon dioxide credits, a proxy of $10/ton was developed for the emission cost. In Advance Plan 6, the Commission determined an environmental cost of $15/ton of emitted carbon dioxide should be added to fossil-fueled plants when comparing construction alternatives.[62] In 2004, the California Public Utility Commission adopted a similar greenhouse gas adder requirement for procurement decisions. The California Commission set the adder at $8/ton with an annual escalation rate.[63] Actual carbon dioxide allowance prices in Europe have been trading at the equivalent of over $30/standard ton.[64] The results of this analysis are discussed in Chapter 5.

[60] Environmental Protection Agency. "National Coal-Fired Utility Projects Spreadsheet." October 2005. http://www.epa.gov/ttn/catc/products.html#misc
[61] Platt's broker based indexes for coal and emissions. http://www.platts.com/Coal/Resources/
[62] Advance Plan 6, Docket 05-EP-6, Order Point 12.6. September 18, 1992.
[63] Presentation by Molly Sterkel, California Public Utilities Commission, to IGCC Study Group, March 10, 2005.
[64] World Gas Intelligence. "Carbon Emissions Policy Starting To Gain Traction in US." February 22, 2006.

Chapter 5: Environment - Air

Changing federal air regulations may also affect the choice of IGCC versus SCPC. Rulemakings are under way both at the federal and state level that will require utilities to invest heavily in pollution control equipment or retire old coal-fired plants. With retirement comes the decision for replacement power. Thus, tightening air regulations are another factor underlying the question of IGCC or SCPC.

Coal-fired power plants are major sources of sulfur dioxide and nitrogen oxide emissions which contribute to the formation of particulate matter and ground level ozone. Coal combustion is also a significant source of mercury emissions. These three emissions have been targeted for major reductions by federal and state regulators. Coal-fired plants are also major emitters of carbon dioxide, the primary greenhouse gas, which is not currently regulated in the U.S. However, movement is under way both in Congress and at the grass-roots level to consider controls on this greenhouse gas. The discussion that follows first describes the changes in federal and state air regulations and then compares emission levels for IGCC and SCPC.

Ozone, Visibility, and the Clean Air Interstate Rule (CAIR)

Currently, DNR is required to address three specific federal Clean Air Act requirements: (1) attaining the National Ambient Air Quality Standard (NAAQS) for ozone in the eastern Wisconsin; (2) meeting visibility goals in national parks and other scenic areas; and (3) reducing the interstate transport of ozone, fine particles, and their precursor pollutants. The three problems are related due to common atmospheric chemistry and precursor pollutants, in particular sulfur dioxide and nitrogen oxide. Coal-fired power plants are by far the major source of sulfur dioxide emissions and are a significant source of nitrogen oxide. Even though emissions of sulfur dioxide and nitrogen oxide have been regulated for decades for their role in the formation of ozone and acid rain, more needs to be done to meet Wisconsin's air quality goals.

To address the ozone problem in eastern Wisconsin, DNR is evaluating nitrogen oxide emission reduction programs. In particular, DNR will focus on rules to implement Reasonably Available Control Technology (RACT) in the southeastern part of the state. RACT is an emission control program affecting sources that emit more than 100 tons per year of nitrogen oxide. DNR expects to ask for hearing authorization on a proposed RACT rule in summer 2006 and finalize the regulations in fall 2006.

To address visibility degradation, DNR is evaluating both nitrogen oxide and sulfur dioxide control programs. As a necessary element of a visibility plan, states must implement Best Available Retrofit Technology (BART), an emission control program for certain major sources of nitrogen oxide and sulfur dioxide. Electric generation is specifically identified in the Clean Air Act for BART consideration. A number of coal-fired power plants in Wisconsin are likely to be affected by BART level controls. DNR expects to ask for hearing authorization on a proposed BART rule in summer 2006 and finalize the regulations in fall 2006.

To address the interstate transport of ozone and fine-particle precursors in the eastern U.S., the EPA Administrator signed the Clean Air Interstate Rule (CAIR) on March 10, 2005. The rule limits sulfur dioxide and nitrogen oxide emissions from power plants in 28 eastern states and the District of Columbia, including Wisconsin. All power plants generating more than 25 MW of power in Wisconsin are potentially affected by the CAIR. However, due to the trading and banking provisions of the federal model rule, it is uncertain which, if any units, in Wisconsin will install emission control equipment. Compliance with phase one CAIR limitations begins in 2009 for nitrogen oxide and 2010 for sulfur dioxide. Compliance with phase two CAIR begins in 2015 for both pollutants. DNR is assessing various options allowed in the CAIR. DNR expects to ask for hearing authorization on a proposed rule in summer 2006 and finalize the regulations in fall 2006.

The evaluation of sulfur dioxide and nitrogen oxide control programs continues. It is not clear at this time whether implementation of RACT, BART and CAIR will be sufficient to meet the federal air quality requirements for ozone and visibility. More emission reductions may be necessary to meet those goals.

CLEAN AIR MERCURY RULE

The Clean Air Mercury Rule (CAMR), signed by EPA on May 18, 2005, establishes "standards of performance" limiting mercury emissions from new and existing coal-fired electric power plants. CAMR also creates a market-based cap-and-trade program that will reduce utility emissions of mercury in two distinct phases. The first phase, due in 2010, is thirty-eight tons nationally. In this first phase, emissions will be reduced by taking advantage of "co-benefit" reductions – that is, mercury reductions achieved by reducing sulfur dioxide and nitrogen oxide emissions under CAIR. In the second phase, due in 2018, coal-fired power plants will be subject to a second cap, which will eventually reduce emissions to fifteen tons nationally. The use of a cap-and-trade approach for achieving mercury reductions will likely delay meeting the second cap until 2025.

In the CAMR, the EPA has assigned each state an emissions "budget" for mercury, and each state must submit a plan detailing how it will meet its budget for reducing mercury from coal-fired power plants. The annual mercury emission budgets EPA established for Wisconsin is 1,780 pounds in 2010, declining to 702 pounds in 2018. Respectively, these budgets represent a 19 percent and 62 percent reduction in mercury emissions from an EPA-calculated baseline. CAMR includes a model cap-and-trade program that states can adopt to achieve and maintain their mercury emissions budgets. States may join the trading program by adopting the model trading rule in state regulations, or they may adopt regulations that mirror the necessary components of the model trading rule.

CAMR affects 48 coal-fired electric generating boilers in Wisconsin operated by eight electric utility companies. The electric utilities affected are Dairyland Power Cooperative, Madison Gas and Electric Company, Manitowoc Public Utilities, MidAmerican Energy Company's Stoneman generator (a subsidiary of WPS Resources), Northern States Power, Wisconsin Electric Power Company, Wisconsin Power and Light Company, and Wisconsin Public Service Corporation.

DNR is assessing various options allowed in the CAMR rule as well as how to reconcile the CAMR rule with the state mercury rule. DNR expects to ask for hearing authorization on a proposed rule in summer 2006 and finalize the regulations in fall 2006. Failure to submit an acceptable state plan will result in the imposition of a federal plan to implement the CAMR in Wisconsin.

Challenges to the Clean Air Mercury Rule

Wisconsin is one of 15 states that are challenging the cap-and-trade approach and other provisions in the CAMR. These same states, in a separate action, have also challenged EPA's decision not to regulate mercury emissions from coal-fired electric plants under the hazardous air pollutant provisions (Section 112) of the Clean Air Act. Instead, EPA developed the CAMR under provisions that allow a more flexible compliance schedule and approach than Section 112 allows. EPA has also recently initiated a formal reconsideration of the CAMR, including many of the issues identified in the states' legal challenge. Public comment is currently being accepted for the issues that EPA will reconsider. The outcome of the lawsuit and EPA's reconsideration may affect the shape of the final rule.

Other Emission Standards

In addition to the rulemakings stemming from CAIR and CAMR, Wisconsin must also address other attainment issues related to the Clean Air Act. These include ozone attainment, visibility impairment, and particulate matter standards. At this time, it is not clear how electric generating sources will be affected by potential actions.

AIR EMISSIONS: MODEL RESULTS

A significant question in evaluating IGCC and SCPC emissions is quantifying potential gains in air quality. The air pollutants emitted from any electric generating plant are related to the efficiency of the pollution control equipment and the efficiency of the plant to convert fuel into heat (*e.g.* heat rate or Btu/kWh). As an extension of the cost model discussed in Chapter 4, this analysis compared emission rates and market costs for IGCC and SCPC. The inputs to this analysis are discussed in detail at the end of this chapter.

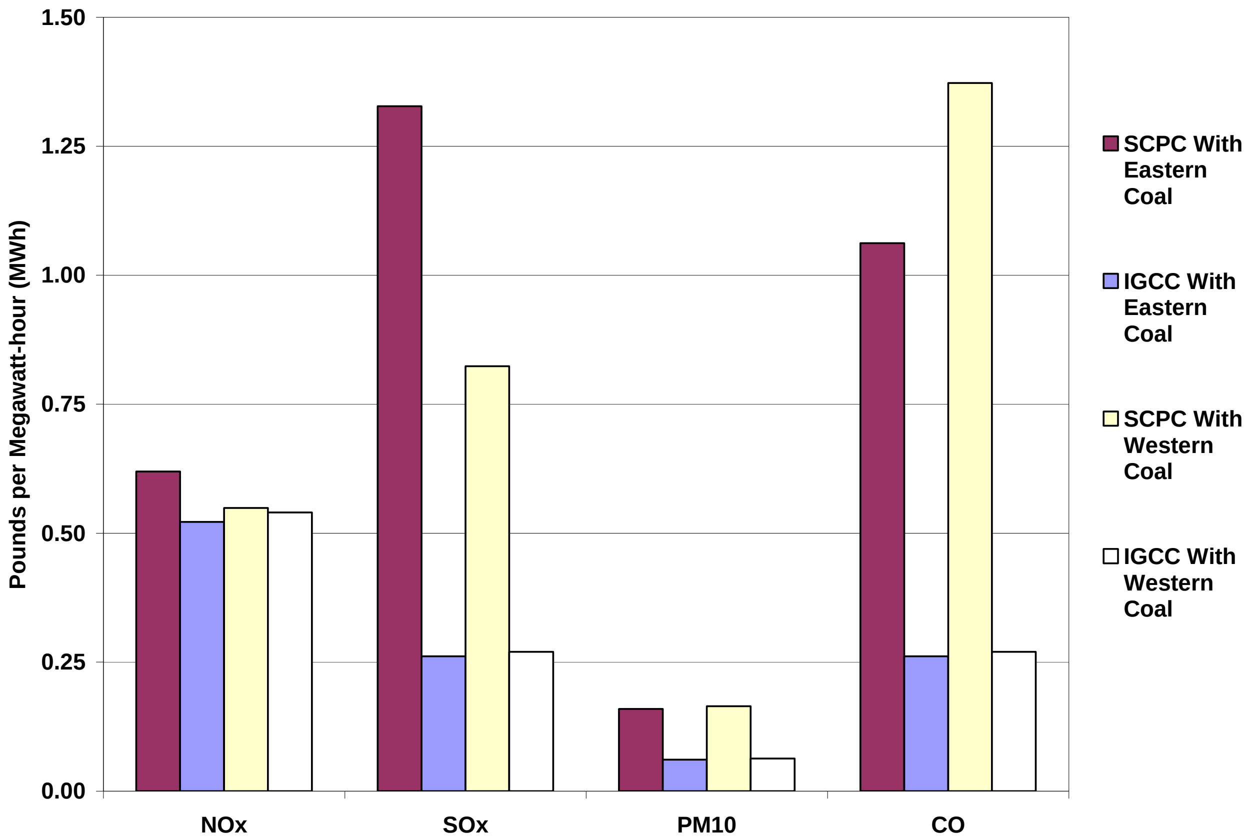
The chart below illustrates the SCPC and IGCC emission rates for nitrogen oxide, sulfur dioxide, particulate matter, and carbon monoxide. The SCPC and IGCC emission rates for nitrogen oxide show little difference; however IGCC shows an advantage over SCPC when comparing sulfur dioxide. This is particularly significant since sulfur dioxide contributes to numerous environmental problems including the formation of fine particulate pollution, haze, and acid rain.

IGCC also shows advantages over SCPC when comparing carbon monoxide and coarse particulate matter emission rates. Carbon monoxide is less significant when considering the overall environmental impact of power plants. And, coarse particulate matter emissions are already very well controlled at both types of power plants.

There are several considerations not addressed in this analysis that could affect the comparison of emissions between SCPC and IGCC. For SCPC units the sulfur dioxide control efficiency of wet flue gas desulfurization equipment used on eastern coal units can be increased to yield a lower emission rate. The wet flue gas desulfurization technology could also be applied in place of dry flue gas desulfurization which is usually the basis of sulfur dioxide emission limits for units firing lower sulfur content coal (*e.g.* western coal or specific low sulfur coal seams).

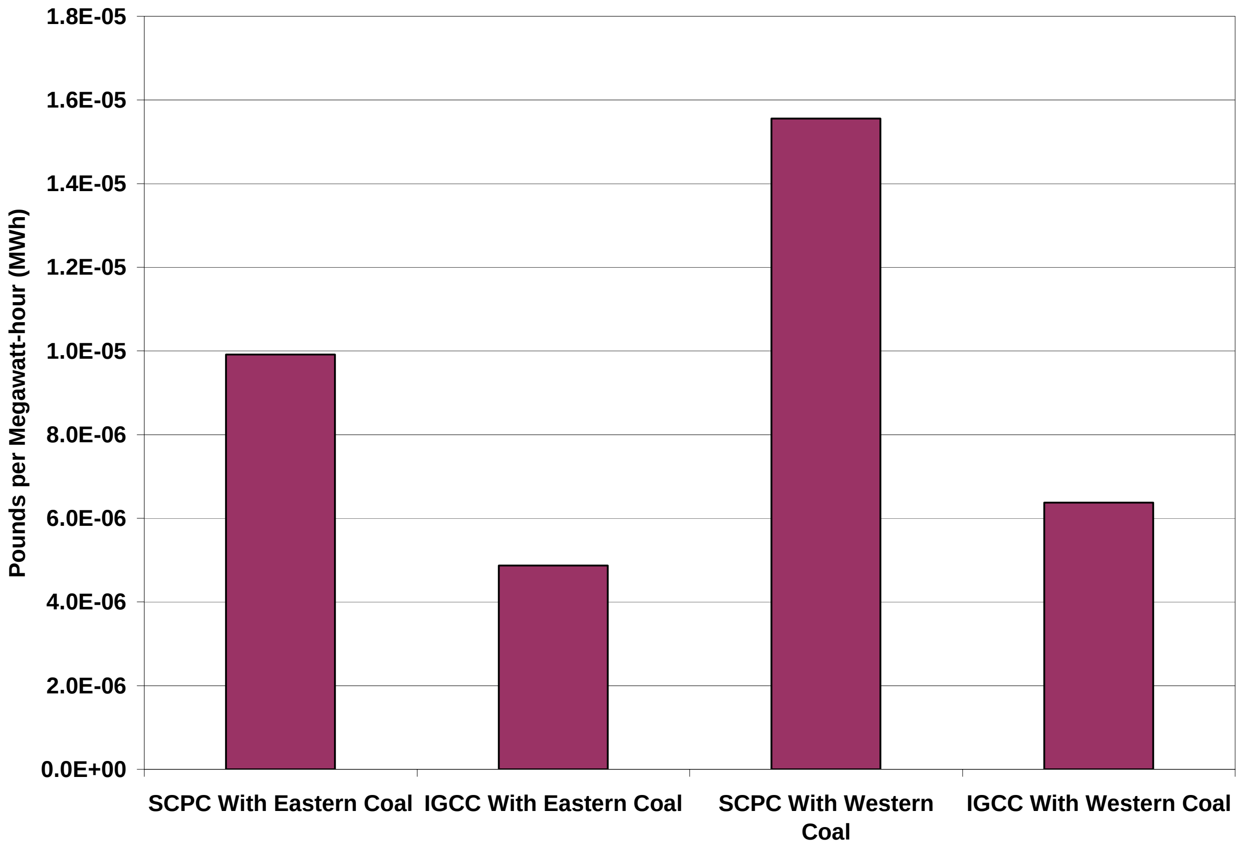
Sulfur dioxide emissions from IGCC plants can also be lowered by using a solvent in the sulfur recovery plant with a higher adsorption efficiency. The use of such a solvent, Selexol, is proposed for a new IGCC plant in Taylorville, Illinois. The additional removal of sulfur from the syngas allows the use of selective catalytic reduction to yield a significantly lower nitrogen oxide emission rate. The additional pollution control in both the SCPC and IGCC cases comes with significant added costs and may be beyond the level that determines the regulatory emission requirement for a new plant.

Figure 5-1 New Coal Power Plant Criteria Pollutant Emission Rates



As discussed in the section on federal air regulations, mercury is the third power plant pollutant that has been targeted for reduction. The emission of this pollutant depends on the mercury content of the fuel, the level of mercury control technology, and a plant's operating efficiency. As shown in Figure 5-2, the mercury emission rates are lower for IGCC units than for the SCPC units for both coal types. This is primarily the result of an anticipated 95 percent control for IGCC versus approximately 88 to 90 percent control for SCPC using the same eastern and western coals, respectively.

Figure 5-2 New Coal Power Plant Mercury Emission Rates

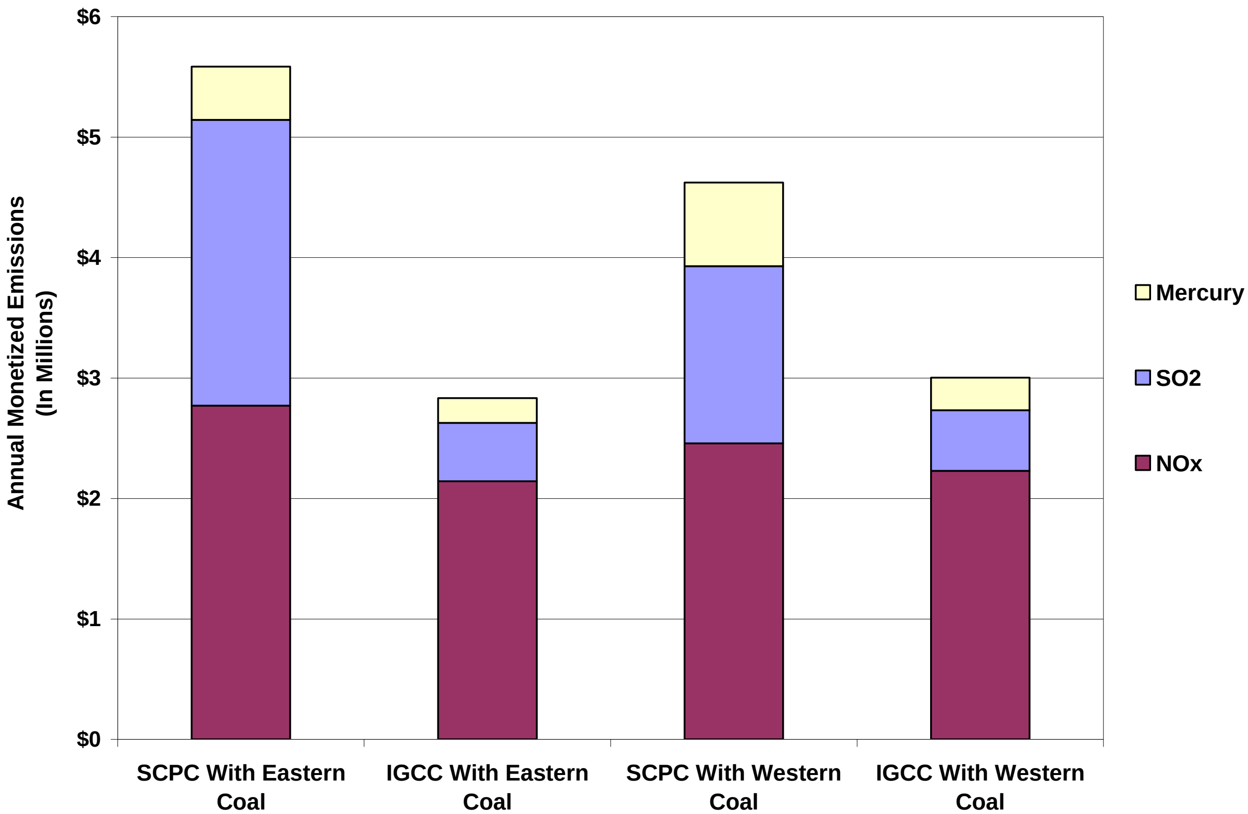


Note: 1.2E-05 is equivalent to .000012 lb./MWh.

A recent trend in the power plant selection process is to "monetize" pollution emissions. Due to EPA's restrictions on nitrogen oxide, sulfur dioxide and mercury, a "cap-and-trade" approach has emerged by which utilities buy and sell pollution credits as a part of their compliance strategy to stay within their emission limits. This has created a market with a pollutant's trading price being used as a rough proxy for the residual cost to society. The price is usually set at the marginal ton removed, that is, the incremental cost of removing the last ton of the pollutant from the combustion gases. Thus, by placing a dollar value on emission amounts, monetizing enables a decision-maker to compare the environmental costs of one technology versus another.

Given their respective emission rates, IGCC fares better when nitrogen oxide, sulfur dioxide and mercury are monetized. The chart below illustrates that due to its lower emissions, IGCC has less environmental cost to society.

Figure 5-3 Comparison of Monetized Emissions for a 600 MW Plant



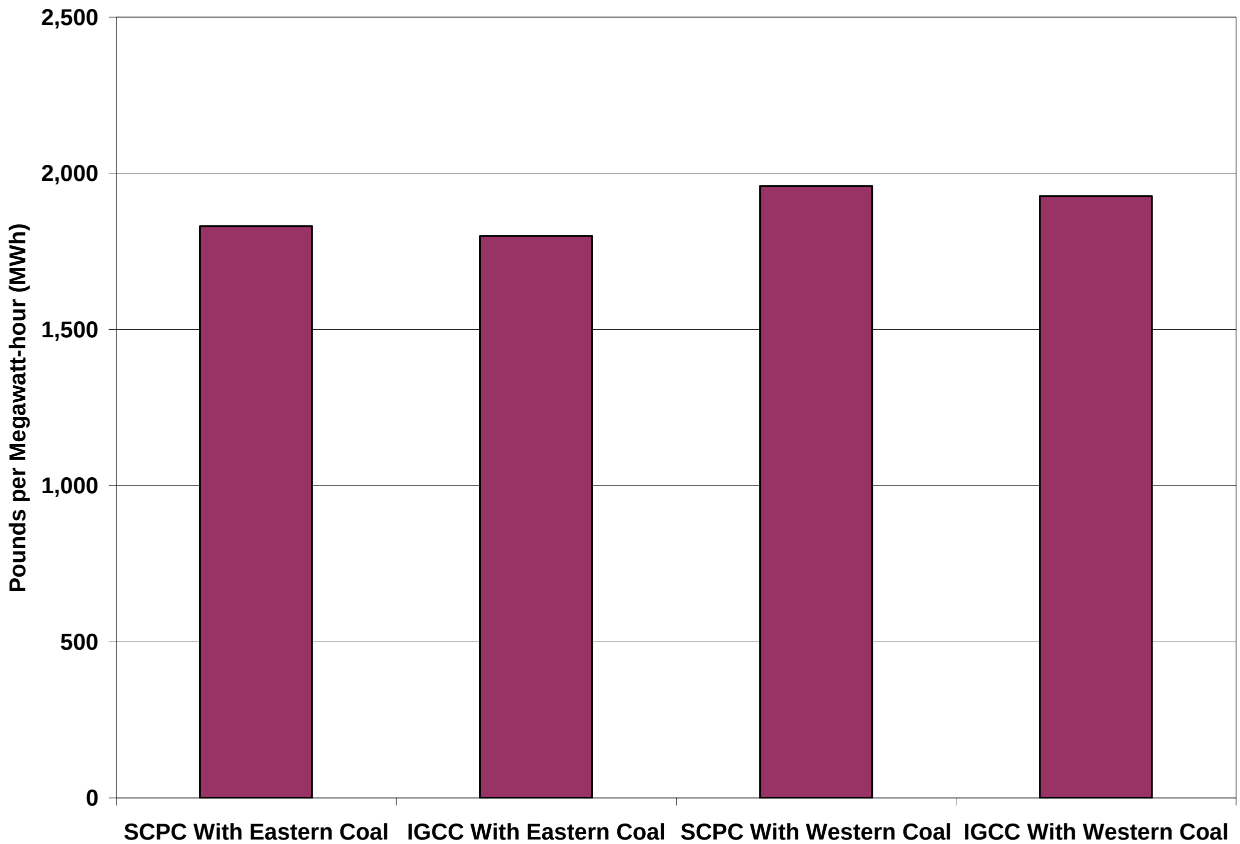
CARBON DIOXIDE

As discussed in Chapter 1, the U.S. does not currently regulate carbon dioxide emissions. However, Congressional energy policy leaders have shown an interest in the issue, and much of the utility industry now views carbon dioxide caps as "inevitable."[65] In the absence of federal action, individual states have stepped in. California's Governor Schwarzenegger issued an executive order in June 2005 establishing greenhouse gas reduction targets for California,[66] and seven Northeastern states have established a Regional Greenhouse Gas Initiative to reduce current carbon dioxide levels by 10 percent by 2020.[67]

Without a carbon capture design, carbon dioxide emission rates from SCPC and IGCC are roughly equivalent as Figure 5-4 illustrates. Although IGCC has an inherent advantage for easier carbon dioxide capture, a plant must be designed to do so. Without that upfront engineering, an IGCC plant has little advantage over an SCPC plant when comparing carbon dioxide emission rates.

[65] Beattie, Jeff. "EPRI Chief: 'Inevitable CO2 Limits Tip Generation Sources." *The Energy Daily*. February 27, 2006.
[66] Presentation by Molly Sterkel, California Public Utilities Commission, to IGCC Study Group, March 10, 2006.
[67] *Electric Utility Week*. Seven Northeast States 'Model' CO2 Rule Expected by June; Draft Ready Soon." February 20, 2006.

Figure 5-4 New Coal Power Plant Carbon Dioxide Emission Rates without Capture Technology



Carbon Dioxide Capture

There are three ways to control carbon dioxide emissions from fossil-fueled technology: (1) by increasing the efficiency of the plant, (2) by reducing the carbon content of the fuel prior to combustion, or (3) by removing the carbon dioxide from the post-combustion gases.[68] IGCC can employ the second technique, removing carbon dioxide from the syngas prior to combustion. SCPC adopts the third technique. This involves "scrubbing" the carbon dioxide from the post-combustion gases using a chemical amine process. This process is both more difficult and expensive than pre-combustion removal.[69] However, with either IGCC or SCPC, carbon capture technology must be incorporated into the design of the plant; it is not a matter of simply adding a piece of equipment later.[70]

No electric generating plants in the U.S., either IGCC or SCPC, currently employ carbon dioxide capture technology. Thus, estimating costs is highly speculative. For carbon capture technology, this study assumes for IGCC a 35 percent increase in capital costs and a 20 percent increase in heat rate due to the energy loss in the resultant low carbon syngas. A 60 percent increase in capital costs and 30 percent increase in heat rate is assumed for post-combustion carbon dioxide separation in an SCPC.[71] O&M costs for IGCC with carbon capture are estimated to be 20 percent higher for fixed and

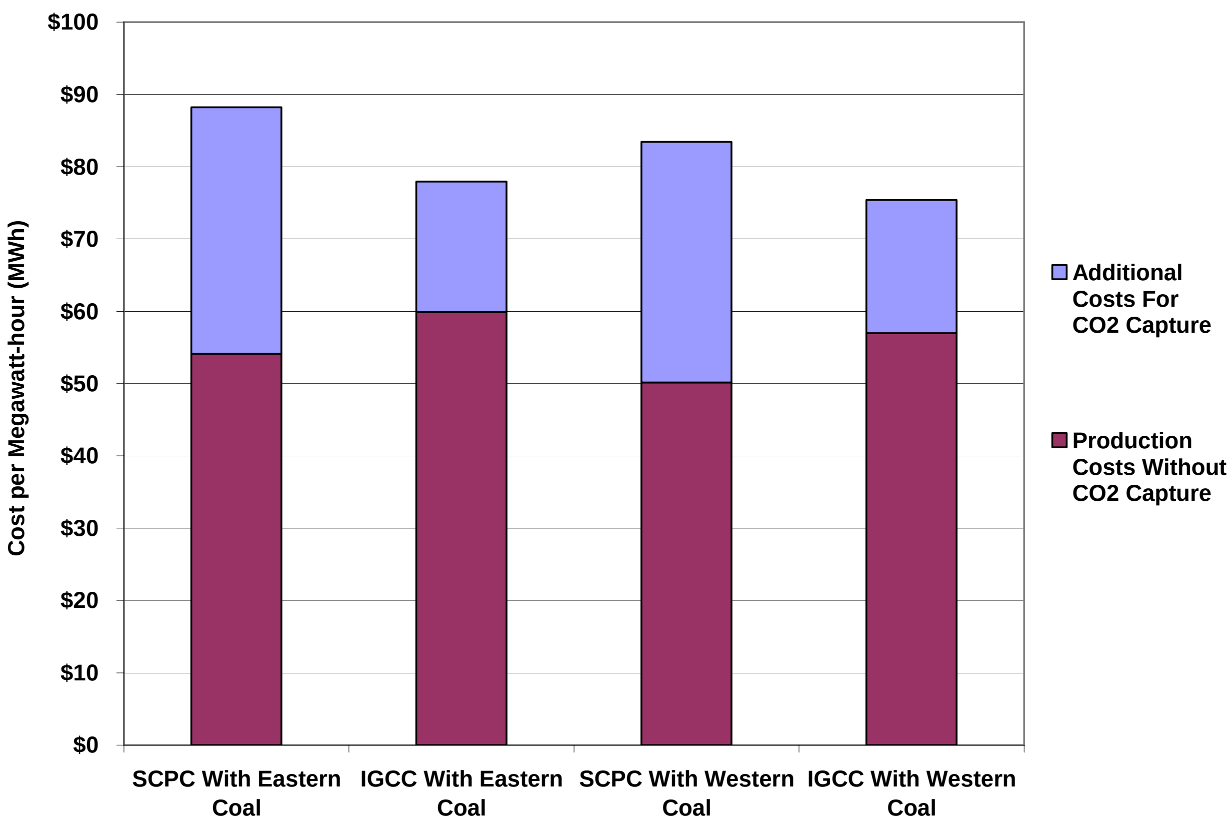
[68] AEP White Paper. "Integrated Gasification Combined Cycle Technology." May 5, 2005, pg. 13.
[69] Herzog, Howard and David, Jeremy. "The Cost of Carbon Capture." http://www.netl.doe.gov/publications/proceedings/01/carbon_seq_wksp/David-Herzog.pdf
[70] Presentation by Stuart Dalton, Electric Power Research Institute, to IGCC Study Group, December 2, 2005.
[71] AEP White Paper. "Integrated Gasification Combined Cycle Technology." May 5, 2005, pg. 13-14.

33 percent higher for variable. For SCPC with carbon capture, O&M costs are estimated to be 30 percent higher for fixed and doubled for variable.[72]

Using these estimates, the analysis showed that adding carbon dioxide capture technology to IGCC and SCPC raised the final cost of electricity for both plants significantly to over $75/MWh of energy generated. However, the cost premium between IGCC and SCPC reversed, such that the final cost of electricity from an IGCC plant with carbon capture technology is approximately $10/MWh *less* than SCPC.

Figure 5-5 below illustrates this reversal. Without carbon capture capability, IGCC is the higher cost option. With carbon capture capability, IGCC is the lower cost option.

Figure 5-5 IGCC and SCPC with and without Carbon Capture Technology



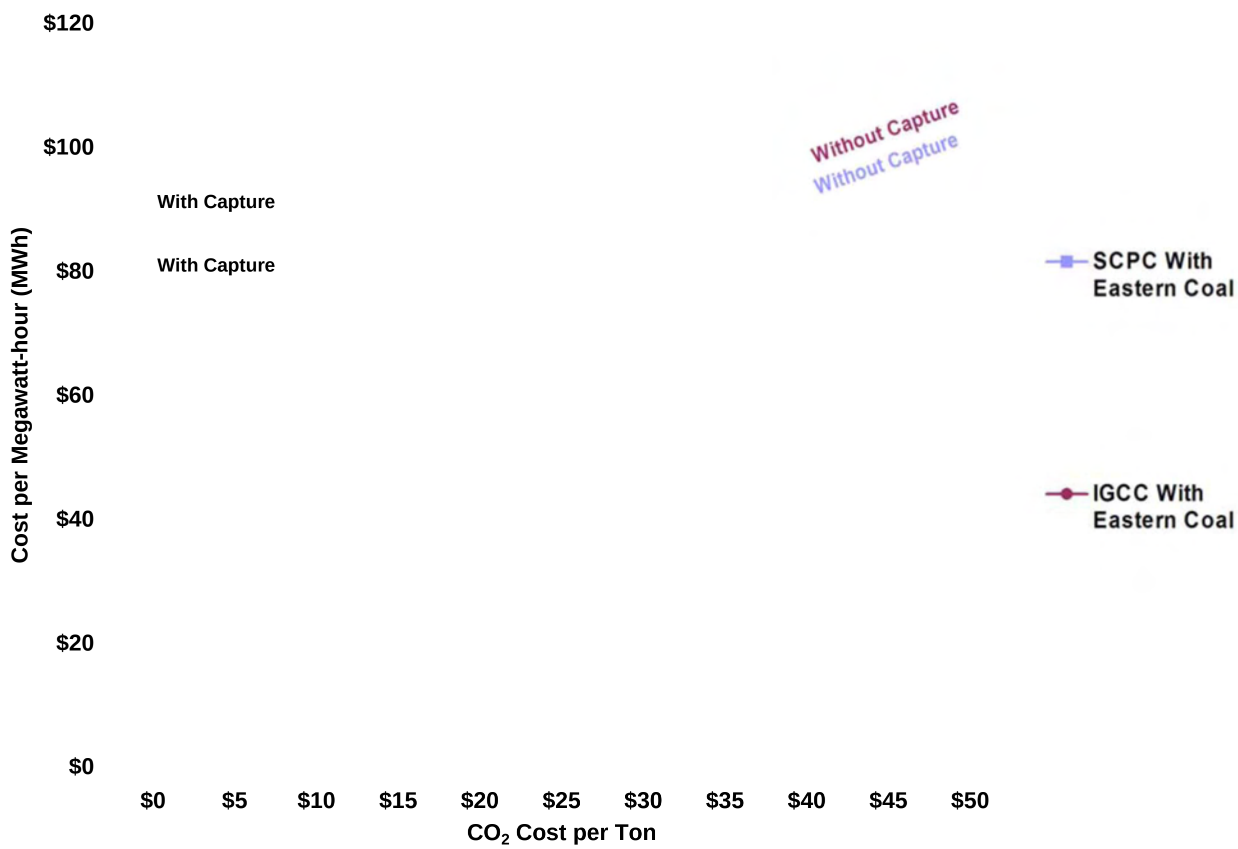
Given the high capital costs and efficiency penalties to capture carbon, it will take a significant impetus to encourage utilities to install control equipment. Should a federal program of carbon restrictions be implemented and carbon trading allowances be established, the price for carbon dioxide emissions would have to be quite high before installing capture equipment in either an IGCC or an SCPC unit becomes economical.

Figure 5-6 demonstrates the crossover points at which carbon capture technology becomes economical for either IGCC or SCPC. At $10 per ton of carbon dioxide emitted, it would be cheaper to pay the monetized price than to design a plant to capture carbon dioxide. At the European trading price of

[72] IEA Clean Centre. "Towards Zero Emission Coal-Fired Power Plants." September 2005, pg. 29

$30 per ton, carbon dioxide capture at an IGCC unit may be more economical than paying an emission fee, before considering transportation and storage costs.[73] Because of its higher capital costs, SCPC with carbon capture capability requires an even higher fee. As illustrated in Figure 5-6, it will take over $45 per ton to make it economical. Such a high fee would likely be politically unsustainable.

Figure 5-6 Comparison of Costs to Monetize Carbon Dioxide Emissions versus Including Carbon Capture Technology



Note: This assumes 100 percent carbon capture capability, which is unlikely for either IGCC or SCPC. Carbon capture rates, given current technology, are estimated at 70 to 85 percent. The crossover point at which carbon capture technology becomes economical will vary by the capture rate.

The figure above does illustrate that installing carbon dioxide capture technology provides a hedge against uncertainty. Baseload plants last for decades, and it is hard to accurately forecast carbon dioxide allowances far into the future. This leaves utilities financially exposed with a potential carbon dioxide liability. For this reason, some utility shareholders have launched an effort to demand disclosure of greenhouse gas emissions and the potential effect of carbon dioxide regulations on the utility companies.[74] Three Wisconsin utilities were included in this effort. The figure above illustrates that a utility can hedge against these potential carbon costs, albeit at very high capital costs, by designing plants with carbon capture capability.

[73] Current estimates of carbon dioxide transportation and sequestration costs are site specific. The costs are likely to be the same irrespective of a choice of SCPC or IGCC.
[74] Content, Tom. "Utilities to List Financial Risks." *The Milwaukee Journal Sentinel.* February 22, 2006.

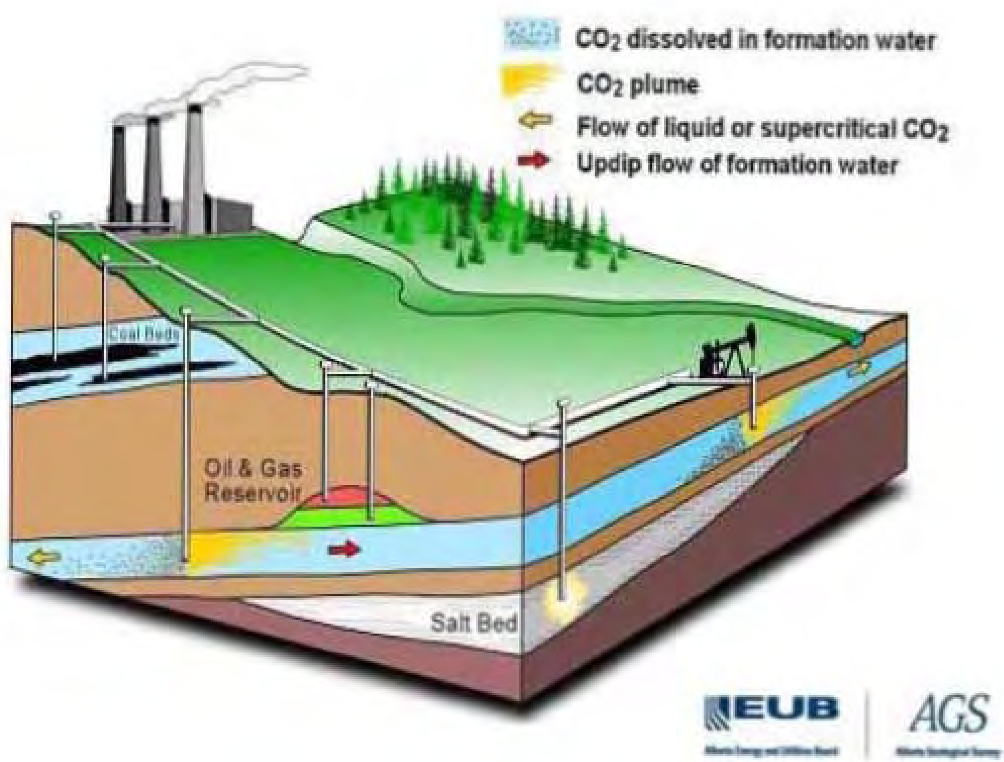
Carbon Sequestration

Once captured, carbon dioxide must then be stored to prevent its escaping into the atmosphere. This involves three basic steps: compressing the carbon dioxide gas into a liquid, transporting it either by truck, rail or pipeline, and storing it in the ground or geologically sequestering it. It is estimated that capture and compression account for 80 percent of the cost to control carbon dioxide while transport and sequestration account for 20 percent of the cost.[75] Biologic sequestration is another storage option by which rain forest preserves or even algae are used to absorb and bind the carbon dioxide into plant material.[76] For carbon dioxide emitting sources on the scale of a commercial power plant, geologic sequestration is probably the more reasonable route.

Two forms of geologic sequestration are being studied. The first is to inject carbon dioxide into depleted or partially depleted oil or natural gas deposits to force out additional petroleum or natural gas. This is known as "enhanced oil recovery" and has the economic benefit of additional oil or natural gas extraction. The additional revenues from the oil or gas extraction can be used to offset the high initial capital costs of IGCC. For this reason, IGCC is particularly intriguing for oil-producing states.

The second form of geologic sequestration is to pump the carbon dioxide directly into stable geologic formations such as coal beds, petroleum deposits, salt domes, or saline aquifers that have no other potential commercial use. These formations could act as natural storage tanks for the carbon dioxide, trapping the gas for the foreseeable future. Figure 5-7 illustrates the options for carbon storage.

Figure 5-7 Carbon Sequestration Diagram



[75] Herzog, Howard. "The Future of Coal: Addressing Carbon and Other Environmental Concerns." MIT, March 27, 2006. http://www.eia.doe.gov/oiaf/aeo/conf/pdf/herzog.pdf
[76] See "Algae—Like a Breath Mint for Smokestacks," The Christian Science Monitor, January 11, 2006.

Widespread use of carbon dioxide geologic storage remains a question. Although many IGCC projects are exploring the possibility of carbon capture and sequestration, such as Xcel Energy's project in Colorado, no generating plants currently employ the technique. However, a North Dakota company has successfully demonstrated carbon dioxide transport and storage in partnership with the EnCana Corporation, a major natural gas and oil producer in Canada. This company, the Dakota Gasification Company, operates a synthetic fuels plant in North Dakota that transports liquid carbon dioxide over 200 miles via pipeline to EnCana's Weyburn oil field in southeastern Saskatchewan. The carbon dioxide, which would otherwise be released into the atmosphere as a greenhouse gas, is captured and sold as a useful byproduct for enhanced oil recovery. In June 2004, the Weyburn project completed its first four years of study, successfully demonstrating the storage of carbon dioxide.[77]

Geography is obviously a critical factor to carbon dioxide storage, and, unfortunately, Wisconsin is not well situated for it. Wisconsin does not possess oil or coal deposits nor are there known salt domes or saline aquifers that may provide opportunities. The most likely prospect for storage sites for Wisconsin is southern Illinois, where deep coal seams, mature oil fields and deep saline aquifers are currently under study for carbon dioxide storage potential.[78] However, Wisconsin will have to develop a way to transport the carbon dioxide to Illinois. A feasibility study of transportation options would be needed.

MODEL INPUTS

This analysis compares the latest emission limits for IGCC and SCPC using both eastern (bituminous) and western (subbituminous) coals as illustrated in Figure 5-8. The emission limits were primarily obtained from the EPA's national working database of proposed and issued permit emission limits for new coal-fired power plants.[79] Based on this data, the Elm Road (eastern coal) and Weston 4 (western coal) projects currently under construction in Wisconsin represent the most stringent issued emission limits nationally for SCPC plants. Figure 5-8 also shows cases where more stringent emission limits are being proposed for new SCPC projects. These proposed limits provide some insight into expected technology improvements but are not used for the IGCC and SCPC emission comparison.

Estimating emission limits for IGCC proved more difficult since an IGCC plant has not been built in the U.S. for a decade. The issued permit limits shown in the table for IGCC with eastern coal are those determined by DNR as part of We Energies' Elm Road IGCC project. However, these limits were not included in the EPA database as the project did not move forward. The Elm Road IGCC emission limits and conditions were also used to estimate emission limits for IGCC with western coal since no permits have been issued for this type of project.

[77] For more information, see http://www.ptrc.ca/access/DesktopDefault.aspx?tabid=81 and http://www.dakotagas.com/Companyinfo/index.html

[78] Presentation by Rob Finley, Illinois State Geologic Survey, to the IGCC Study Group, February 10, 2006.

[79] USEPA, "National Coal-Fired Utility Projects Spreadsheet," updated October 2005. http://www.epa.gov/ttn/catc/products.html#misc

Figure 5-8 Issued and Proposed Emission Limits for New Coal-Fired Plants

Eastern Coal	Super-Critical (lbs/mmBtu)		IGCC (lbs/mmBtu)	
	Issued (1)	Proposed	Issued (2)	Proposed
NO_X	0.07	0.06	0.06	0.059
SO_2	0.15	0.13	0.03	0.033
PM_{10}	0.018	0.0018	0.011	0.007
CO	0.12	0.10	0.03	0.036
Hg	1.12 E-6 or 90% control		5.6E-06 or 95% control	95% control
Western Coal	**Super-Critical (lbs/mmBtu)**		**IGCC**	
	Issued (2)	**Proposed**	**Issued**	**Proposed**
NO_X	0.06	0.05		
SO_2	0.09	0.06		
PM_{10}	0.018			
CO	0.15	0.14		
Hg	1.7 E-6 or 88 % control			

Source: EPA's working database "National Coal-Fired Projects Spreadsheet" – October, 2005
1) Elm Road emission limits (IGCC emission limits determined by DNR, but not contained in EPA database)
2) Weston 4 emission limits

The "issued" emission limits in Figure 5-8 have been converted to output based emission rates using the plant heat rates discussed in Chapter 4. The resulting emission rates, in pounds per MWh, are used to compare the technologies throughout the analysis.

Chapter 6: Environment - Land, Water and Solid Waste

For any coal-fired plant, factors used to determine site selection include land availability, access to water, rail and transmission lines, solid waste disposal and community acceptance. Both IGCC and SCPC need access to rail and transmission lines, so these are not distinguishing factors. IGCC shows an advantage when comparing water use and solid waste disposal needs, and SCPC may have a slight advantage when considering community acceptance.

Land Requirements

As site shape and topography heavily dictate a project's configuration, it is difficult to estimate the land requirements for IGCC or SCPC in the abstract. However, IGCC and SCPC will likely require equivalent acreage for rail storage and delivery tracks, coal storage, electrical switchyards, cooling towers, access roads, storage buildings, and any buffer. Based on existing large coal plants in Wisconsin, land for these operations amounts to at least 50 acres, before accounting for buffer lands. This estimate may vary considerably once a specific site is chosen.

IGCC and SCPC do differ in their land requirements when considering plant design. The existing IGCC plant designs have used about 25 to 30 acres for technology-specific components, including the gasification block, power block and air separation unit and control room. The recently approved Weston 4 SCPC generating unit uses approximately 20 acres for the boiler-generator building and back-end emissions control equipment.

Thus, IGCC requires slightly more land for technology-specific components, but the larger land needs for coal, rail and cooling facilities are roughly equivalent between the two technologies. Overall, the total acreage needed for the two types of plants can be assumed to be roughly equivalent.

Water Use

The major water use in an IGCC plant is for condensing low pressure turbine exhaust steam, followed by water consumed by the gasification process and water used for cooling the compressors in the air separation unit. The largest water use in an SCPC plant is also for condensing steam, followed by water used in the flue gas desulfurization system, if a wet scrubber system is used.

Overall, IGCC plants are expected to require about 30 percent less water on a daily basis than an SCPC plant.[80] The lower water need is an advantage IGCC plants have over SCPC units, particularly in areas

[80] Presentation by Norman Shilling, GE Energy, and Lee Schmoe, Bechtel Corporation, to IGCC Study Group, December 2, 2005.

where water is limited. IGCC also has less thermal discharge into the supplying water source if once-through cooling is employed at the plant.

Solid Waste Disposal

The primary solid wastes of an IGCC plant are slag and sulfur, both of which have value as salable byproducts. Slag, which is a vitrified, glass-like product, can be used for the production of roof shingles, blasting grit, chip seal material for roads and parking lots, or as an alternative to sand, gravel or crushed stone for pavements, parking lots or foundation bases. The sulfur is captured in the clean-up of raw syngas as either elemental sulfur or sulfuric acid; production quantities are directly related to the sulfur content of the coal (*e.g.* eastern versus western coal). Sulfuric acid has many industrial uses while elemental sulfur is used primarily in the production of fertilizers. Sensitivities were included in the cost analysis that increased and decreased the value of the sulfur byproduct. The analysis showed little impact on the overall cost of electricity from an IGCC unit.

Solid wastes from an SCPC plant include bottom ash, sludge and possibly fly ash, depending on the desulfurization process. Bottom ash is a beneficial byproduct commonly used as an alternative for sand, gravel, and crushed stone pavement, and parking lot and foundation base materials. Sludge will be created during the desulfurization process. With a dry process, the sludge has no beneficial reuse and must be landfilled. With a wet process, gypsum is produced, which can be sold for the manufacture of wallboard. Fly ash will also result from a wet desulfurization process, which also has a beneficial use as admixture for cement. Thus, depending on the type of desulfurization process, SCPC plants may have costs for disposing of solid waste and landfill requirements.

Rail and Transmission Considerations

Most new large SCPC or IGCC power plants depend on railroads to deliver coal to the plant site and transmission switchyards to connect to the larger grid. Both the proximity to rail lines and major transmission lines are significant factors affecting site selection. While either rail or power lines can be extended to a possible power plant site, the feasibility of extending either of these decreases rapidly as the distance increases. Both cost and the difficulty of acquiring necessary right-of-way limit the feasibility of such extensions. Since IGCC and SCPC have like needs for these factors, neither type of plant would be favored based on rail or transmission considerations.

Unique Community Impacts

The effects of a new power plant on the surrounding community, and the perception the community has of that plant, would likely be quite similar for IGCC and SCPC. Both comprise large industrial facilities with frequent rail deliveries, loud operations, large buildings, smokestacks, coal piles, electrical switching stations and power lines. IGCC may invoke slightly more concern due to its gasification unit, which acts as a small chemical factory. However, both types of generation would likely face community opposition.

Overall

In comparing land, water and waste disposal issues, IGCC and SCPC face many similar challenges. Although both plants will need a sizable amount of land, IGCC shows some advantage over SCPC given its reduced water and waste disposal needs. However, on the question of total environmental impact, these differences are probably less significant than the question of air emissions.

7

Chapter 7: Financing

OVERVIEW

Given IGCC's limited track record in the U.S., the finance community generally views this technology as a greater risk than SCPC. Standard and Poor's reviewed IGCC in August 2005 and found that IGCC projects face higher construction risks, higher capital costs, and that reliability issues are "front and center" despite IGCC's substantial environmental benefits.[81] Similarly, a director of Fitch Ratings also found in 2005 that, "…IGCC projects will be subject to increased levels of completion and operation risks, generally requiring stronger mitigation."[82] These concerns are not unfounded; past projects have not all been successfully implemented.[83] While IGCC technology is considered promising, it is generally recognized that for IGCC to be competitive in the near-term, financial incentives need to be developed.[84] This will be a policy decision for the state to consider, particularly in light of IGCC's long-term environmental promise.

The federal energy bill, Energy Policy Act of 2005, contains substantial incentives for IGCC technology. These incentives include loan guarantees, cost sharing arrangements and tax credits. However, most of these incentives will go to the early adopters of IGCC technology. Projects are under development in California, Colorado, Illinois, Minnesota, Ohio and other states. No utility in Wisconsin has announced an intention to pursue IGCC in the near future; therefore, Wisconsin is not poised to benefit from the federal incentives. Further, it should be noted that the Act only authorizes the funding of the incentives; the actual appropriation will have to occur during the budgeting process.[85]

The state and its regulatory agency can also play a role in providing incentives for IGCC, as several states have already done. These incentives could take the form of cost-sharing or grants, tax or credit-based incentives, or favorable regulatory treatment. Tax-based incentives include an investment tax credit, a production tax credit, and allowing accelerated depreciation, among other options. These incentives would impact the state's taxpayers rather than just the specific utility's ratepayers. Credit-based incentives include loan guarantees, securitized financing, direct loans and tax exempt financing among other options. Favorable regulatory treatment primarily includes ensuring cost recovery, providing additional profit on the project to offset the risk or ensuring the purchase of electricity from an IGCC facility. Figure 7-1 summarizes existing and proposed incentives.

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[81] Standard and Poor's. "Prospects Improve for IGCC Technology in U.S., but Challenges Remain." August 25, 2005.

[82] Remec, Gregory. Director, Fitch Ratings. "Credit Quality." *Project Finance*. September 2005, pg. 103.

[83] A first generation plant, the Pinon Pine IGCC unit in Nevada, never operated as an IGCC power plant due to technical difficulties. The power block was converted to natural gas, and the gasification portion was terminated. Electricity was generated and revenue received from the operation of the unit as a natural gas plant. The Nevada Commission disallowed $47 million associated with the project.

[84] Presentation by Brian Oakley, Scully Capital, to IGCC Study Group, April 6, 2006.

[85] E^3 Ventures, "Energy Policy Act of 2005 – A Summary of Gasification Incentives & Programs." 2005, pg. 3.

Figure 7-1 Existing or Proposed Incentives for IGCC

	Fed	CO	IL	IN	KS	MN	NY	OH	PA	TX	WI
Cost sharing and grants	✓	✓	✓			✓	✓	✓	✓	✓	
Tax-Based											
Investment tax credit	✓		✓	✓	✓						
Production tax credit											
Accelerated depreciation											
Other taxes (includes property, sales, local taxes)			✓		✓	✓	✓			✓	
Credit-Based											
Loan guarantees	✓	✓							✓		
Securitization											
Direct loans	✓		✓		✓		✓	✓	✓		
Favorable Regulatory Treatment											
Accelerated recovery of investment				✓							✓
Incentive returns on investment				✓							✓
Timely recovery of preconstruction costs				✓							✓
Timely recovery of financing costs during construction				✓							✓
Cost recovery				✓					✓		
Guaranteed purchaser						✓	✓		✓		
Incentives to purchase electricity from an IPP											
Other Incentives											
Agency assistance in obtaining financial and other support		✓					✓				
Reduced permitting requirements						✓					
Delayed environmental compliance									✓		

Note: This table is not exhaustive.

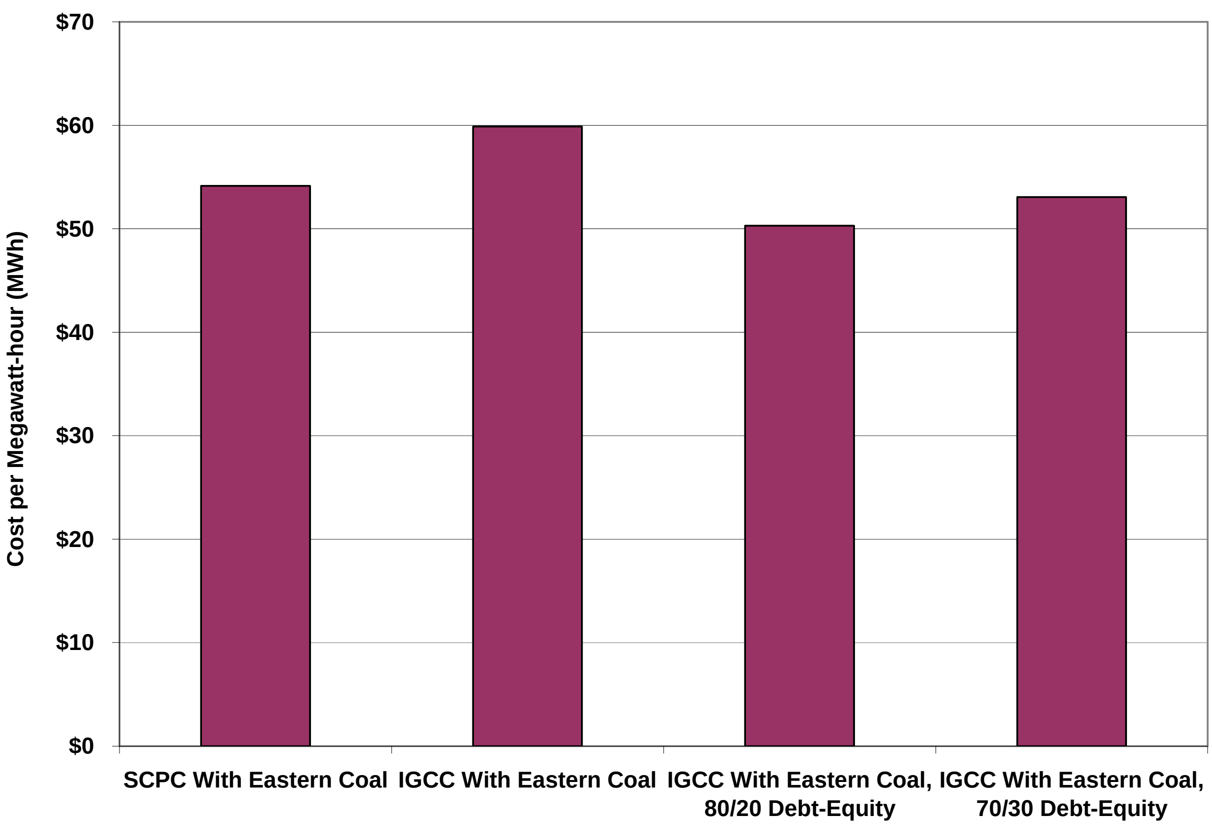
The remainder of this chapter discusses each financing incentive in detail. However, it should be noted that the benefit of a particular incentive will vary by the type of electricity provider. Investor-owned utilities, independent power producers, and public power agencies will view incentives differently given their respective need for cheaper credit and their interest in tax offsets. For example, tax-based incentives will have no value for a public power agency, and loan guarantees may provide little incentive for investor-owned utilities since they already have access to low cost debt. Independent power producers, however, may be very interested in both these incentives.

Of the incentives discussed in detail in the following sections, the option that appears to have the greatest impact on the final production cost of electricity for IGCC is securitized financing. Securitized financing allows a utility to issue low-interest bonds that are backed by a dedicated revenue stream.

Essentially, securitization pledges a utility asset (*e.g.* a dedicated revenue source from ratepayers) as security for the bonds. The more certain the revenue stream, the lower the financing costs. The Commission would have to approve the collection of this dedicated stream.

In order to further benefit from the low-interest debt, securitized financing also involves adjusting the debt-to-equity ratio. Typical regulated utility projects are financed at approximately 50 percent debt to 50 percent equity. By altering this ratio to include more low-cost debt, the financing costs for the project can be reduced. Figure 7-2 below illustrates the impact of various securitization scenarios on the final production cost of electricity for IGCC with eastern coal. The figure's two securitized financing estimates are based on using 80 percent debt to 20 percent equity and alternately 70 percent debt to 30 percent equity. These are conservative estimates. Under securitization, equity can be reduced to a fraction of a percent.[86]

Figure 7-2 Impact of Securitized Financing on IGCC Final Production Cost of Electricity



The figure shows that securitized financing significantly lowers the final production cost of electricity from an IGCC plant, making it cost-competitive with an SCPC plant. However, the dedicated revenue stream shifts the project risk to the ratepayers. While it reduces the risks to the utility's stockholders, it also reduces the amount of equity on which the stockholders can earn a return. Wis. Stat. § 196.027, the "environmental trust financing" legislation, allows securitized financing for pollution control equipment.

[86] In docket 6630-ET-100, Wisconsin Electric Power Company proposed that the capitalization of the special purpose entity be perhaps as low as, but no lower than, 0.5 percent equity. (October 12, 2004, Financing Order in docket 6630-ET-100, page 12.)

There would have to be a specific policy determination by the state, as well as a legislative change, to extend the special financing arrangement to IGCC.

COST SHARING AND OTHER GRANTS

Most IGCC funding has been through federal cost sharing and grants. Cost sharing and grants are valuable to investor-owned utilities, independent and merchant power producers, and public power organizations because they are an effective means of reducing upfront capital costs. However, the Electric Power Research Institute reports that applicants have in the past been required to repay 100 percent of the government's actual cost-sharing contribution to the project upon demonstration of successful commercialization.[87] Under such an arrangement, the benefits are reduced.

Various states and their economic development or industry promotional agencies have also provided grants. These types of grants are largely found in states that have significant coal deposits or have a need to reinvigorate an industrial zone. Most of these grants are relatively minor compared to the total cost of the plant and require a policy determination by the state that pursuing IGCC is a priority for economic or other reasons. These grants would provide more benefit to entities in need of initial development capital.

Federal: Title IV Subtitle A of EPAct 2005 provides an annual amount of $140 million for years 2006 through 2014 (aggregating $1.26 billion) of cost-sharing grants for the IGCC technologies. For commercial demonstration applications, the cost-sharing grant can be up to 50 percent of the project cost. Under the cost-sharing guidelines, the IGCC owner cannot be required to repay the federal share as a condition of getting the award.[88] The funds are not solely for IGCC demonstration plants, but can also be used for other gasification projects and establishing centers of excellence at educational institutions. Only a few IGCC plants are expected to benefit from the cost-sharing grants. Subtitle B provides an assortment of incentives, but these incentives are targeted to specific projects and will not be available for Wisconsin utilities. Subtitle C (§ 421) provides for an aggregate of $2.5 billion to be spent during the years 2006 through 2013 to encourage the generation of new sources of advanced coal-based power with priority to technologies that are not yet cost competitive and achieve greater efficiency and environmental performance. Government cost sharing will not exceed 50 percent.

Colorado: On February 8, 2006, House Bill 06-1322 was introduced. This bill proposes to transfer $6 million per year for three years from the severance tax trust fund to a proposed clean energy development fund. Of this amount, up to $3 million per year will be available for the study, engineering, and development of an IGCC facility using Colorado or other western coal, or both.

Illinois: On January 6, 2006, Governor Rod Blagojevich announced that the Illinois Department of Commerce and Economic Opportunity will provide $2.5 million for front-end engineering and design work for the Taylorville Energy Center IGCC project. In addition, he announced that the public-private Illinois Clean Coal Review Board would provide an additional $2.5 million. While such economic development and coal promotional grants help with start-up costs and fees, they are small relative to the total cost of the plant ($1.1 billion). They provide the most benefit to independent and merchant power producers. Economic development grants are more likely available in areas with higher unemployment where the power plant would stimulate jobs.

[87] Electric Power Research Institute. "A CoalFleet Working Paper: Financial Incentives for Deployment of IGCC." March 10, 2005, pg. 5.
[88] Section 988(e) of EPAct 2005

Illinois: Since July 2001, the Illinois Department of Commerce and Economic Opportunity has had authority to provide financial assistance of up to $100 million to any new electric baseload generating facility (this would include IGCC power plants). While eligible coal facilities must, in general, have capacity of at least 400 MW and support the creation of at least 150 new Illinois coal mining jobs, recent legislation exempts IGCC plants from these requirements. The amount of money available for assistance is based on a formula tied to the state occupation and use tax receipts paid on Illinois-mined coal used at the facilities.

Minnesota: The Mesaba Energy Project has received grants from the state renewable energy development fund and from Iron Range Resources, a state agency.

New York: The New York Power Authority will establish a fund of $10 million per year over five years. The resulting $50 million fund will be awarded to the winner(s) of a solicitation conducted by the authority and the New York Energy Research and Development Authority.

New York: If requested by a project participant, the New York Power Authority may also become a minority share partner in the power plant project.

Ohio: The Ohio Coal Development Office (OCDO) provides co-funding for research, development and pilot plants for non-commercial technologies. The funding is for the lesser of one-third of the project cost or $5 million. The OCDO could co-fund up to three IGCC plants before the technology is considered commercial.

Pennsylvania: Governor Edward Rendell proposed a plan which includes priority funding for IGCC through the state's Economic Development Financing Authority and Energy Development Authority. The Pennsylvania Energy Development Authority can also award grants.

Texas: H.B. 2201, which became law on June 18, 2005, added "a gasification project for a coal and biomass mixture" to the eligibility list for receiving grant money under the Innovative Energy Demonstration Program.

TAX-BASED INCENTIVES

Investment Tax Credit

Investment tax credits provide the taxpayer a credit against regular income tax otherwise due based on a percentage of taxpayer investment in specified equipment and facilities. Investment tax credits have high value for investor-owned utilities, but no value for public power organizations which do not pay taxes. The value to independent and merchant power producers depends on their profitability. The investment tax credit provides additional cash flow in the early years of the project. For the taxing agency, the investment tax credit reduces revenues in the year the incentive is taken. However, the revenue loss will decline over time as a result of lower depreciation in subsequent years due to tax basis reduction.[89]

Federal: Title XIII (§ 1307) of EPAct 2005 provides for investment tax credits equal to 20 percent of the eligible investment. The eligible investment is any property which is necessary for the gasification of

[89] Oakley, Brian T. "Deploying Integrated Gasification Combined Cycle Units: What Will it Take?" June 27, 2005.

coal, not the entire IGCC plant. The aggregate investment tax credit is limited to $800 million which translates into $4 billion of eligible investment. While investment tax credits could help bridge the gap in capital costs and the enrollment period is three years,[90] Wisconsin utilities cannot be sure of receiving any of this incentive.

Illinois: An investment tax credit is available to IGCC power plants through the High Impact Business statutes.

Indiana: The Clean Indiana Energy Act provides investment tax credits for IGCC plants located in Indiana which use Indiana coal to generate electricity for Indiana customers. The credit equals 10 percent of the first $500 million and 5 percent of the investment above that amount. The credit must be taken in ten annual installments beginning in the year the facility is placed into service and the amount is based on the percentage of Indiana coal used at the facility. Approval of the tax credit comes through the Indiana Economic Development Corporation.

Kansas: House Bill No. 2904 proposes investment tax credits for IGCC plants located in Kansas, which use Kansas coal to generate electricity for Kansas customers. Like the Indiana credit, the credit equals 10 percent of the first $500 million and 5 percent of the investment above that amount. The credit must be taken in ten annual installments beginning in the year the facility is placed into service and the amount is based on the percentage of Kansas coal used at the facility.

Production Tax Credit

A production tax credit provides the taxpayer with a credit against income tax otherwise due based on the amount of energy actually produced from a facility, rather than on the capital cost of the facility. The difference between the production tax credit and the investment tax credit is that the production credit is allowable only to the extent the facility actually produces electricity while an investment credit is available without regard to the level of performance of the facility so long as it has been placed in service.[91] The owner receives no benefit unless the technology is successfully implemented. There currently are no production tax credits in place for IGCC power plants in the U.S.

Accelerated Depreciation

Accelerated depreciation has high value for independent and merchant power producers, medium value for investor-owned utilities, and no value for public power organizations which do not pay taxes. Accelerated depreciation shifts depreciation to the present, but does not increase the overall deduction, resulting in no additional deductions over the asset's life.[92] However, the accelerated depreciation results in lower taxes at the beginning of the asset's life, and consequently, increases cash flow. Its benefits come from the time value of money. A 10-year recovery period has been available for IGCC plants in certain industrial applications, but there currently are no accelerated depreciation rates in place for IGCC power plants in the U.S.

Other Tax Exemptions

In areas of economic depression or where the local governments deem a proposed development would develop a good tax base, governments will give temporary tax exemptions to stimulate development.

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[90] E[3] Ventures, "Energy Policy Act of 2005 – A Summary of Gasification Incentives & Programs." 2005, pgs. 4 and 11.
[91] Electric Power Research Institute. "A CoalFleet Working Paper: Financial Incentives for Deployment of IGCC." March 10, 2005, pg. 6.
[92] Oakley, Brian T. "Deploying Integrated Gasification Combined Cycle Units: What Will it Take?" June 27, 2005.

An example is the Mesaba Energy Project, which will be located in an area of high unemployment and is expected to bring both temporary construction jobs and permanent plant jobs.

Illinois: IGCC power plants can apply for a High Impact Business designation. The program offers sales tax exemption on building materials and equipment and a utility tax exemption.

Illinois: The Illinois property tax code allows local taxing districts to abate property taxes for up to ten years for new generating plants.[93] There is a limit on the amount of property tax that can be abated based on the equalized assessed valuation of the facility and the taxing district's total taxes from the facility.

Kansas: House Bill No. 2904 proposes that any new IGCC power plant property or any expanded IGCC power plant property be exempt from all property taxes levied under the laws of the state of Kansas for a limited period of time.

Minnesota: The Mesaba Energy Project site is expected to be designated as a tax free "Job Opportunity Building Zone" under Minnesota law. This affords the project a holiday from various state and local taxes for up to 12 years.

New York: The initial project sited will qualify for Empire Zone benefits irrespective of where it is located in the state. Such benefits include 10-year exemption to sales tax on purchases of goods and services and a credit against business tax.

Texas: H.B. 2201, which became law on June 18, 2005, added "a gasification project for a coal and biomass mixture" to the list of investments eligible for limitations on their appraised values to be used for school district taxing purposes.

CREDIT-BASED INCENTIVES

Loan Guarantees

Regardless of the grants, cost sharing arrangements, or tax credits, the plant owner will still need to finance its share of the plant. The financing could be difficult. To date, no IGCC facilities have been project financed in the United States.[94] Project finance is debt that is largely a claim against the cash flows from a particular project rather than against the firm as a whole.[95]

Loan guarantees permit a project sponsor to obtain debt financing at an interest rate closer to the guarantor's cost of money. A loan guarantee may permit a higher leveraged capital structure, substituting low cost-debt for high cost equity. Non-recourse loan guarantees can also shift a portion of a project's technology risk to the guarantor.[96] Loan guarantees have high value for independent and merchant power producers, low value for investor-owned utilities, and no value for public power organizations. Investor-owned utilities with lower credit receive more benefit than investor-owned utilities with higher credit. Loan guarantees can minimize federal costs while providing significant

[93] There is some uncertainty whether the IGCC power plant needs to receive a High Impact Business designation.
[94] Remec, Gregory. Director, Fitch Ratings. "Credit Quality." *Project Finance.* September 2005, pg. 100.
[95] Brealey, Richard A. *et al.* *Principles of Corporate Finance.* 2006, pg. 1002.
[96] Electric Power Research Institute. "A CoalFleet Working Paper: Financial Incentives for Deployment of IGCC." March 10, 2005, pgs. 4-5.

project benefit. The risk borne by the guarantor depends on the ability of the IGCC owner to service and repay the loan. Assured revenue streams substantially reduce that risk.

Federal: Title XVII of EPAct 2005 establishes a loan guarantee program to provide up to 80 percent federal loan guarantees to gasification technologies. IGCC plants must meet eligibility requirements. In the absence of sufficient appropriations, the project owners may pay for the federal costs of their loan guarantee. It is assumed that a Wisconsin IGCC plant would qualify for loan guarantees. However, the loan guarantee could come at a cost to the IGCC plant if demand exceeds federal appropriations levels.

Proponents of federal loan guarantees have proposed a "3 Party Covenant" whereby the federal government would provide a guarantee; the equity investor would contribute equity for 20 percent of project costs and negotiate performance guarantees to develop, construct, and operate the IGCC plant; and the state regulatory commission would agree to a dedicated revenue stream to cover the return of capital, cost of capital, and operating costs.[97] There are risks to ratepayers as dedicated revenue streams can only exist when the ratepayers are required to pay for the power plant regardless of its final cost and successful operation.

The reduced cost of energy from this three-party financing comes from: (1) funding construction financing costs on a current basis by adding construction work in progress to the rate base and recovering these financing costs as they are incurred, rather than accruing these financing costs; (2) lowering the cost of debt by the amount of spread between the owner's and federal government's bond costs; and (3) providing a significantly higher ratio of debt-to-equity in the financing.[98] Wisconsin utilities already receive the first benefit for any major construction project. The second benefit is more important to entities with low credit ratings. The third benefit is valuable only to the extent that the additional debt does not negatively impact the entity's current credit ratings.

Colorado: On February 1, 2006, House Bill 06-1281 was introduced. This bill proposes to direct the Public Utility Commission to support proposals by Colorado utilities to propose, fund, and construct IGCC power plants using western coal. The Commission would grant the utility a construction permit and issue a declaratory order for cost recovery if it finds that the project can be constructed for reasonable cost and rate impact, taking into account the demonstrative nature of the project, the amount of federal, state, or other moneys available for the project, and other listed criteria. Upon approval, the utility shall be entitled to fully recover, through a separate rate adjustment clause, the prudently incurred costs. These provisions are consistent with the state guarantees promoted by proponents of the "3 Party Covenant."

Pennsylvania: Pennsylvania Energy Development Authority can award loan guarantees.

Securitized Financing

Securitized financing pledges an asset as security for the bonds. First mortgages are the best known and simplest form of securitization. However, in recent years, the term securitization often refers to revenue streams pledged to service and repay the debt. The more certain the revenue stream and its assured adequacy to service and repay the debt, the lower the financing costs. The "3 Party Covenant" proposal is based on this concept. To ensure federal guarantee of the loan, the Commission could issue an irrevocable order authorizing the collection of adequate charges. This charge would be collected

[97] Rosenberg, William G. et al. "Deploying IGCC Technology in this Decade with 3 Party Covenant Financing: Volume 1." ENRP Discussion Paper 2004-07, Kennedy School of Government, Harvard University, July 2004.
[98] Research Reports International. *Coal Gasification for Power Generation*. September 2005, pg. 78.

regardless of the operational performance of the IGCC power plant. As noted earlier, this shifts the risks associated with construction and operation of the IGCC power plant to the ratepayers. Under securitization, federal guarantees are not necessary. In addition, under securitization, the debt leverage can be increased substantially higher than the 80 percent used for three-party financing, lowering the financing costs further.

Wisconsin: 2003 Wisconsin Act 152 created Wis. Stat. § 196.027 enabling environmental trust financing. Under Wis. Stat. § 196.027, utilities can securitize environmental control activity which includes costs associated with the construction and installation of environmental control equipment for an existing energy utility plant and the associated retirement of the old equipment. The statute allows the securitization of the securities with environmental control property, which is the right to collect environmental control charges that are authorized in the Commission's irrevocable order. While no securities have been issued to date under the statutes, the Commission issued an order on October 12, 2004, in docket 6630-ET-100 authorizing Wisconsin Electric Power Company to issue environmental trust bonds. If the bonds are issued, retail customers will have to pay monthly non-bypassable charges to recover the principal, interest, and related costs of the bonds. The interest on these bonds is not tax-exempt.

Direct Loans and Tax-Exempt Financing

Under this arrangement, a governmental agency issues bonds and uses the proceeds to make a loan to the project owner to cover a portion of the cost of the facility. These bonds are referred to as Private Activity Bonds. Two dimensions of the financing are important – whose credit backs the securities (governmental agency or project) and whether the interest on the securities is tax-exempt. Generally, the interest rate is close to those of the lending agency if the bonds are backed by the agency's credit. Independent and merchant power producers have more use for direct loans than investor-owned utilities because of their lower credit. Public power organizations issue tax-exempt bonds and often can borrow at rates lower than the federal government. Consequently, they do not benefit from direct loans. The governmental agency may also issue revenue bonds where the underlying credit is the project. Private Activity Bonds may have limited appeal if they are not tax-exempt. Eligibility for federal tax-exemption is based on meeting Internal Revenue Service (IRS) rules, which include purpose and aggregate issuance limitations.

Federal: Loans could be available through the Clean Air Coal program. Loans are at the cost of federal borrowing.

Illinois: Under the Clean Coal and Energy Project Financing codes, the Illinois Financing Authority can issue up to $1.7 billion in bonds for new generation projects, including IGCC power plant projects. Any borrower or its affiliates are limited to a maximum loan from the authority of $450 million. Most bonds will be revenue bonds backed by the credit of the project with only $300 million in aggregate backed by the state's credit. Some projects may be eligible for federal tax exemption.

Kansas: House Bill No. 2904 proposes that the Kansas Development Finance Authority be authorized to issue revenue bonds in amounts sufficient to finance a new IGCC power plant. The revenue bonds and income on the revenue bonds will be exempt from all state, county and municipal taxation in the state of Kansas, except Kansas estate taxes.

New York: Up to $1 billion of the state's federal tax exempt volume cap allocation, in amounts of no more than $200 million per year, will be made available for qualifying participants who successfully complete the competitive solicitation.

Ohio: Ohio Air Quality Development can help with financing.

Pennsylvania: The Pennsylvania Energy Development Authority can award loans.

Wisconsin: Wisconsin utilities have in the past borrowed funds for the construction of pollution control equipment under the provisions of Wis. Stat. § 66.1103. In such cases, a municipality issued tax-exempt securities that were backed by long-term debt securities issued by the utility. The proceeds were used to finance investor-owned utilities' pollution control facilities. The Tax Reform Act of 1986 removed pollution control facilities from the list of eligible projects.

REGULATORY INCENTIVES

The regulatory agency can also be a source of financial incentives. Through its ratemaking process, it can accelerate the recovery of investment costs, provide incentive returns on IGCC investments, ensure timely recovery of preconstruction costs and financing costs during construction, and provide incentives to purchase electricity produced by an independent or merchant power producer. The costs of such incentives would be borne by the ratepayers of the utility involved, not the state's taxpayers.

Indiana: IC 8-1-2-6.7 allows the depreciation of clean coal technologies over a period of not less than 10 years or the useful economic life, whichever is less, and not more than 20 years if it finds that the facility where the clean coal technology is employed utilizes Indiana coal or justifies why it does not utilize Indiana coal. IGCC appears to qualify as a clean coal technology. Because the code relates to utility regulation, the depreciation would be related to rate recovery, not income taxes. The incentive would be financed by ratepayers, not taxpayers.

Indiana: Chapter 8.8 Utility Generation and Clean Coal Technology states that the commission shall encourage clean coal and energy projects by creating financial incentives for clean coal and energy projects, if the projects are found to be reasonably necessary. The purchase of fuels produced by a coal gasification facility is defined as a clean coal and energy project and one of the allowable incentives is a higher return on equity on the project.

Indiana: IC 8-1-2-6.1 allows the recovery as operating expenses preconstruction costs (including design and engineering costs) for clean coal technologies if the facility where the clean coal technology is employed utilizes Indiana coal or justifies why it doesn't utilize Indiana coal. IGCC appears to qualify as a clean coal technology.

Indiana: Since 2002, Indiana law allows the state commission to include in the value of that utility's property the value of the qualified pollution control property under construction. IGCC plants would qualify under the definition of qualified pollution control property.[99]

[99] One of the requirements listed in IC 8-1-2-6.8 is that the technology either "(A) was not in general commercial use at the same or greater scale in new or existing facilities in the United States at the time of enactment of the federal Clean Air Act Amendments of 1990 (P.L.101-549); or (B) has been selected by the United States Department of Energy for funding under its Innovative Clean Coal Technology

Pennsylvania: Governor Edward Rendell has also proposed to subject the electricity from IGCC power plants to the pricing and cost-recovery provisions of the state's Alternative Energy Portfolio Standard which would allow the utilities to recover relevant costs to support their investment.[100]

Guaranteed Purchaser of Electricity

As noted earlier, financial markets are concerned with assured revenue streams. For investor-owned utilities and public power organizations, the output can be expected to be used for its traditional customer base. However, for independent and merchant power producers, the output must be sold to other parties, thus, having a guaranteed purchaser of the electricity is important. In principle, IGCC can be commercially financed, but financial markets need a utility behind them, with a lease or power-purchase agreement that has been approved by regulators and perhaps even state legislators. Consequently, the existence and terms of a purchased power agreement for IGCC plant output will affect the ability to borrow and the terms of the borrowing. The more favorable the terms for the IGCC merchant operator, from an assured revenue stream perspective, the more the risk to the utility and/or its ratepayers of paying for power not received. In addition, the creditworthiness of the purchaser will be important. Current rating services impute a debt equivalence for purchased power agreements. Consequently, the purchased power agreement will also affect the utility's ratings, or if capitalization is adjusted for the purchased power agreement's debt equivalent, the capital costs are passed on to the utility's ratepayers.

Minnesota: In connection with the Mesaba Energy Project, Minnesota enacted legislation that entitles the project to a long-term power purchase agreement with Xcel Energy, subject to a public interest finding by the Minnesota Public Utilities Commission.[101] It also has the right to supply energy to meet Xcel's clean energy technology purchase requirement and to be considered as a supply option for any fossil-fuel fired generation proposed. The IGCC project indicates that the bulk of the total tariff under its proposed purchased power agreement is tied to a capacity payment that is fixed and flat for the life of the project.

New York: The New York Power Authority will enter into a power purchase agreement starting in 2012 or sooner.

Pennsylvania: In November 2005, Governor Edward Rendell proposed a plan allowing long-term contracts between IGCC projects and their electricity customers.

Other Incentives

Other options have been proposed to ease the regulatory process for building an IGCC plant or delaying the time period for installing pollution control equipment to allow for IGCC construction as a substitute.

Colorado: On February 1, 2006, House Bill 06-1281 was introduced. This bill proposes that the Public Service Commission, the Department of Health and Environment, the Governor's Office of Economic Development, and the Governor's Office of Energy Management and Conservation provide utilities

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program and is finally approved for such funding on or after the date of enactment of the federal Clean Air Act Amendments of 1990 (P.L.101-549)."

[100] While a news release from the Pennsylvania Governor's Office implies that this is a proposal, other sources indicate that eligibility has already been granted with the November 30, 2004 passage of Act 213.

[101] Excelsior Energy Petition for Approval of a Purchase Power Agreement to the Minnesota Public Utilities Commission. Docket E6472/M-05-1993, December 2005.

with assistance in seeking and obtaining financial and other support and sponsorship from federal and state agencies and institutions.

Minnesota: The legislature exempts the Mesaba Energy Project from the state commission's construction permit process and provides eminent domain rights for present and future generation and transmission needs. The project is not exempt from environmental review and air, water and waste permitting procedures.

Pennsylvania: Governor Edward Rendell proposed a plan to allow coal-fired power plants to continue to operate without installing new pollution controls until 2013 if they agree to replace the plants by that year with IGCC technology. The proposal will need approval from the EPA.

New York: The Governor's Office of Regulatory Reform, the New York Power Authority, the New York Energy Research and Development Authority and the Department of Environmental Conservation will work together to identify "shovel ready" sites for development of IGCC power plants.[102]

SUMMARY

In sum, there are many avenues for a state or regulatory agency to develop incentives for IGCC to make up for the perceived risk premium. These incentives will have varying effects, depending upon the dollar amount involved and the type of electricity producer seeking the benefits. Securitized financing appears to have the greatest impact on the final production cost of electricity from an IGCC unit. This impact is enough to close the cost gap between IGCC and SCPC. If a policy decision is made to encourage IGCC, securitized financing may be worth further investigation.

[102] While Governor George E. Pataki's February 13, 2006, announcement named IGCC as the technology, other clean coal technology is not being ruled out in New York's program if proven to be more cost-effective.

Chapter 8: Economic Development

There are three primary factors to consider when analyzing IGCC's economic development potential for the state – the multiplier effect of construction expenditures, job creation, and the possibility of co-production, or the ability of an IGCC unit to produce synthetic natural gas, liquid fuels or chemicals when not producing electricity. On the first two issues, many of the development possibilities are not unique to IGCC, but apply to any large-scale utility infrastructure project. IGCC does offer unique opportunities on the third factor, co-production, but Wisconsin may not be well suited to capture these due to geography and the state's existing industrial base.

In general, putting money into the economy from both the construction and operation of a facility, be it an electric generating facility or any other industrial facility, will have a positive impact on economic development. The jobs created at the facility inject additional income into the local economy, encouraging additional growth and jobs. In addition, new electric generation, from any type of generation, will increase electric reliability. Reliable electric capacity is essential for retaining and attracting businesses in Wisconsin. Shared revenue payments can also be a benefit to the host community and defray the costs of additional services such as police and fire protection for a new facility. None of these economic benefits is unique to an IGCC facility.

For job creation, IGCC does not differ significantly from other large-scale utility infrastructure projects. While there may be a slightly greater need for specialized laborers to build and employees to run the gasification technology, this is a slight difference from conventional coal projects. On the whole, job multipliers do tend to be higher in the electric utility sector than in other parts of the economy. That is, one job in the utility sector can create additional jobs elsewhere in the economy.[103]

With respect to co-production, IGCC does offer additional economic opportunities that do not exist with a conventional coal-fired plant. When not producing electricity, the gasifier technology could be used to produce syngas, hydrogen, chemicals, fertilizers, or other liquid fuels. Syngas, which is interchangeable with natural gas and may be injected directly into the existing pipeline system, has been of particular interest lately due to volatile natural gas prices.

This co-production flexibility may offer additional economic opportunities when electricity generation is not needed. However, due to the capital costs for the additional equipment needed to allow co-production, GE Energy, one of the major vendors of gasification technology, stated that it has not yet found IGCC with co-production technology to be economical.[104] An additional institutional barrier may

[103] A study of the Kansas City, Missouri economy, which is used here as a proxy for the urban area in southeastern Wisconsin, found a local job multiplier of 2.7. See: "Regional Multipliers—A User Handbook for the Regional Input-Output Modelling System RIMS II," U.S. Department of Commerce, Bureau of Economic Analysis, 3rd edition, March 1997, Table 2.4, page 56.
[104] Presentation by Norman Shilling, GE Energy, to IGCC Study Group, Dec. 2, 2005.

also be the allocation of the benefits and costs of co-production between a regulated utility and an unregulated customer.

However, co-production does have substantial promise. The Eastman Chemical plant in Tennessee has a long history of making industrial petrochemicals from a dedicated coal gasification unit. Also, the Department of Defense has indicated an interest in using coal gasification to make a synthetic petroleum distillate that can be used as a fuel for everything from troop trucks and tanks to helicopters and jet fighters.

Unfortunately, geography may hinder Wisconsin's ability to benefit from IGCC's co-production possibilities. Wisconsin does not have the coal deposits that Illinois, Montana or Ohio do, all states where coal gasification is being hotly pursued. Wisconsin also does not have the oil fields or other geologic formations that could provide storage basins for sequestered carbon dioxide, such as Texas (also a state enthusiastically pursuing IGCC). Finally, Wisconsin does not have a large petroleum refining base or chemical industry that might make use of the products that an IGCC unit with co-production capability could produce.

On the whole, IGCC and SCPC are comparable in their impacts to the local economy and their ability to create jobs. Although IGCC may offer co-production opportunities that SCPC does not, Wisconsin is not well suited to benefit from these opportunities.

Chapter 9: Policy Options

During the course of the study group's review of IGCC, it has been commented that it is not a question of *if* IGCC but *when*. The review showed that under current operating and environmental performance benchmarks, IGCC is not a clear winner. The technology does, however, hold promise for the future, particularly if reliability concerns are addressed and carbon emission limits are imposed. This leaves the decision-maker with a difficult policy question: does IGCC hold enough promise in the near future that the state should pursue it now? This is a particularly timely question given the near-term building needs of many of the state's utilities.

The IGCC Study Group discussed policy options should the state seek to pursue IGCC. The intent of this discussion was a brainstorm, to provide a menu of options for a decision-maker. The goal was not to reach consensus solutions but rather to develop a preliminary list of possibilities. The ideas that follow range from the radical to the more conventional and likely would have varying levels of support among stakeholders. All will require additional analysis before implementation. The ideas are organized into four categories: legislative/regulatory, financial, research and development, and other.

LEGISLATIVE/REGULATORY

1. Require Detailed Information About Only One Site in a CPCN Application

Pursuant to Wis. Stat. §§ 1.11 and 196.491(3)(d)3., an energy provider seeking to build a new power plant must propose alternate project sites during the permitting process. In recent years, the PSC has interpreted these statutes to require an applicant to provide at least two feasible sites; these sites must offer different packages of costs and benefits. Last year the Wisconsin Supreme Court in *Clean Wisconsin v. Public Service Commission*, 2005 WI 93, 282 Wis. 2d 250, 700 N.W. 2d 768, affirmed this interpretation.

One means of promoting IGCC development in Wisconsin would be to adopt rules or enact a statutory change that would relax the two-site requirement. Rather than require detailed information about two sites, the PSC could require an IGCC project applicant to describe its process of evaluating potential sites, provide detailed information only about its preferred site, and give general information about the alternative locations that it evaluated and rejected.

Action to Consider: Amend Wis. Stat. § 196.491 or Wis. Admin. Code § PSC 111.53.

2. Narrow the Site Selection Process

In order to control the cost of new IGCC plants by maximizing the use of existing infrastructure, Wisconsin may find it useful to promote IGCC construction where electric generating plants are already in place. Electric generating plants that currently use natural gas as a fuel could be refueled as IGCC units. This would also have the benefit of reducing the state's dependence on natural gas.

The PSC could encourage such refueling by narrowing the breadth of the site selection process that an IGCC project applicant must undertake. While this would make site selection easier for an IGCC applicant, it would not go as far as option one above. Such an exemption currently exists for cogeneration and repowering projects. For example, under Wis. Admin. Code § PSC 111.53(2)(b)2, a construction applicant for a repowering project can meet the two-site requirement by providing information about two sites that are both located at the existing generating plant. The PSC could expand this exemption to include projects to refuel a natural gas-fired plant and convert it to an IGCC facility.

Action to Consider: Amend Wis. Admin. Code § PSC 111.53(2)(b).

3. Allow Siting at Either Brownfield or Greenfield Locations

In 2003 Wisconsin enacted a law requiring that large new electric generating plants be located at brownfield sites, to the extent practicable. Wisconsin could grant IGCC facilities an exemption from this requirement.

Action to Consider: Amend Wis. Stat. §§ 196.49(4) and 196.491(3)(d)8.

4. Monetize Greenhouse Gases in the PSC Resource Selection Process

When comparing the costs of different methods of producing electricity, some costs are routinely quantified in monetary terms and some, such as environmental costs, are not. In 1992 the PSC, through its Advance Plan docket, assigned a monetary value to the emission of greenhouse gases. The PSC judged that, given the long operating lives of new power plants, utilities would probably be subject to future regulations requiring them to capture and sequester carbon dioxide emitted by the plants. In Advance Plan 6 (1992) the PSC assigned a value of $15/ton of carbon dioxide emitted to account for the cost that utilities would likely begin incurring to comply with future regulations.[105] With the elimination of the Advance Plan process in 1997, the treatment of greenhouse gases is less clear.

California is now monetizing greenhouse gases. Its Public Utility Commission adopted rules that include a cost of $8/ton of carbon dioxide in its procurement selection process, with an annual escalation rate.[106] Wisconsin could engage in a similar rulemaking that would establish clear guidelines for the treatment of carbon dioxide emissions.

Action to Consider: New PSC rulemaking.

[105] Advance Plan 6, Docket 05-EP-6, Order point 126. September 18, 1992.
[106] Presentation by Molly Sterkel, California Public Utilities Commission, to IGCC Study Group, March 10, 2005.

5. Clarify DNR Nitrogen Oxide Control Requirement

DNR sets maximum emission limits to control the release of nitrogen oxides. For example, Wis. Admin. Code § NR 428.04(2)(g)3. sets the minimum performance for a new IGCC unit were one to be built in the Milwaukee area.

The standard means of controlling nitrogen oxide emissions in a traditional coal combustion unit is to use selective catalytic reduction, a post combustion method of reducing nitrogen oxide emissions. Some clarification of DNR rules may be useful to explain whether its minimum performance standards for an IGCC unit includes selective catalytic reduction. This issue is currently addressed for individual projects during the Best Available Control Technology/Lowest Achievable Emission Rate (BACT/LAER) review as part of the construction permitting process.

Action to Consider: Modifying Wis. Admin. Code ch. NR 428, subch. 1.

6. Consider IGCC as the Best Available Control Technology for New Coal Plants

During its permitting process for a new coal-fired power plant, DNR must evaluate the expected air emissions and determine if the new facility will use BACT to limit those emissions. This is a "top-down" analysis that first considers the most stringent emissions control available for a similar source; only if that technology is technically or economically infeasible does DNR evaluate the next level of control. A national clearinghouse determines emission profiles for pollution control equipment and ranks what is BACT.

In several states, some organizations have pursued legal challenges to the BACT analysis. In Wisconsin, DNR's analysis was challenged as part of We Energies' Power the Future coal plants. These organizations have argued that IGCC is a comparable technology that should be included in the BACT analysis for pulverized coal and SCPC projects.

In December 2005, the EPA issued a letter stating that because IGCC is a fundamental redesign of a conventional coal project, it is not required in the BACT analysis.[107] Several national environmental organizations are challenging this determination in court. Wisconsin could go beyond this federal standard and impose its own requirement that IGCC be considered in the BACT analysis for new coal-fired facilities. To do so, however, Wisconsin could amend state laws to require that BACT analyses for coal-fired power plants include consideration of IGCC.

Action to Consider: Amend Wis. Stat. § 285.63.

[107] Letter from Stephen Page, EPA Director, to Paul Plath, E3 Consulting. December 13, 2005.

7. Establish Carbon Dioxide Performance Standards

In 2005, California Gov. Schwarzenegger established state targets for reducing greenhouse gas emissions. California's goal is, by 2010, to reduce its greenhouse gas emissions to 2000 levels; by 2020, to drop to the state's 1990 levels; and by 2050, to reduce these emissions to 80 percent below its 1990 levels.[108]

A means of implementing these restrictions in Wisconsin or in the Midwest would be to create a "cap-and-trade" program similar to that currently in use for sulfur dioxide emissions. Utilities could also be required to cap their total emissions of carbon dioxide at a prescribed level per MWh.

Seven states in the Northeast (Connecticut, Delaware, Maine, New Hampshire, New Jersey, New York and Vermont) have already signed an agreement that creates a Regional Greenhouse Gas Initiative. Under this Initiative, the states are committed to creating a carbon dioxide cap-and-trade program.[109] Wisconsin could initiate such a program on its own or with neighboring states.

Action to Consider: New legislation.

8. Modify the Renewable Portfolio Standard

Wisconsin has a Renewable Portfolio Standard that requires electric utilities to produce an increasing percentage of their power from renewable resources or to purchase "renewable resource credits" from other providers. Earlier this year Wisconsin enacted legislation, 2005 Wis. Act 141, that expands this requirement.

In Minnesota, a utility operating or purchasing power from an IGCC plant can use some of the plant's power to offset its requirements under the state's Renewable Portfolio Standard. Minnesota law treats two kilowatt hours (kWh) of electric power from an IGCC facility as being equivalent to one kWh from renewable resources. Wisconsin could do the same as a means of promoting IGCC development.

Action to Consider: Amend Wis. Stat. § 196.378.

9. Modify the Energy Priorities Law

Wis. Stat. § 1.12 prioritizes generating options for meeting the state's energy demand. The highest priority is energy conservation, then renewable resources and combustible nonrenewable fuels. The lowest priority is power produced by burning high-sulfur coal. The PSC is required to implement these statutory priorities when it makes energy-related decisions to the extent cost-effective, technically feasible and environmentally sound.

As a means of recognizing that IGCC plants have the potential to be cleaner than conventional coal facilities, Wisconsin could revise the Energy Priorities Law by placing IGCC with sequestration above other coal alternatives in the priorities list. It could also recognize the benefits of carbon capture and sequestration by raising IGCC with sequestration to the same priority as renewable resources.

Action to Consider: Amend Wis. Stat. § 1.12.

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[108] Presentation by Molly Sterkel, California Public Utilities Commission, to IGCC Study Group, March 10, 2005.
[109] *Electric Utility Week*. December 26, 2005, pg. 16.

10. Require Turnkey Bidding and Performance Guarantees

A major risk for the developers of IGCC facilities is the possibility that this technology will fail to perform properly, with problems either of heat rate or availability. This presents considerable risk to the utility and its ratepayers. Wisconsin law could be amended to allow the PSC to grant preference to an IGCC proposal that is backed by minimum heat rate and performance guarantees in its resource selection process, or the PSC could issue a policy statement indicating that it will give preference to an IGCC proposal that includes such performance guarantees.

Action to Consider: New legislation or issuance of PSC policy statement.

FINANCIAL

Chapter 7 describes a number of financial incentives that could promote IGCC development. In summary, they are:

11. Apply Environmental Trust Financing to IGCC Projects

In 2003 Wisconsin enacted a law, Wis. Stat. § 196.027, allowing utilities to issue "environmental trust bonds." The law allows utilities to apply to the PSC for a financing order, under which the proceeds of these bonds can be used to finance the cost of installing environmental control equipment. Financing orders irrevocably authorize the utility to impose charges upon its ratepayers that are sufficient to recover the costs of the bond issuance, even if the environmental control facilities do not perform as anticipated. The bonds are not considered debt of the utility and are a low cost, low risk means of financing environmental controls.

Wisconsin could expand this law, allowing the PSC to issue financing orders that enable IGCC development as well as provide inexpensive funding for environmental controls.

Action to Consider: Amend Wis. Stat. § 196.027.

12. Allow an Incentive Return on Equity

Indiana authorizes its electric utilities to earn an increased return on equity for building IGCC power plants. The incentive is meant to provide a credit boost to offset the increased risk of the technology. Wisconsin could do the same using the new fixed financial parameters law, Wis. Stat. § 196.371. To reduce the adverse effect on electric rates, the incentive return on equity could be limited to just the gasifier portion of the power plant.

Action to Consider: Apply Wis. Stat. § 196.371 to an IGCC project.

13. Allow an Incentive Adder to IGCC Purchase Power Agreements

Indiana also allows financial incentives for utilities that purchase syngas from an independently-owned coal gasification plant. A similar incentive could be created to encourage utilities to purchase power from independently-owned IGCC power plants. Currently, a utility that signs a purchase power agreement earns no return on equity from its purchase.

Action to Consider: New legislation or PSC rulemaking.

14. Assign Carbon Dioxide Property Obligations

A Wisconsin utility that purchases power from a renewable resource generating facility also acquires the renewable resource credits that are associated with the renewable energy. State law is silent regarding which party would be responsible for controlling carbon dioxide emissions in a purchased power agreement with a fossil-fueled generator. If carbon dioxide emissions are capped, the responsibility for these emissions will become significant. Assigning carbon dioxide emission responsibility to the purchasing utility would encourage the purchase of power from IGCC plants that capture and sequester their carbon emissions. It would also encourage the purchase of power from renewable resources.

Action to Consider: New legislation.

15. Allow Utility Risk Recovery

Because IGCC technology has a limited operational history, the risks of completion delays and less reliable operation are higher than for a standard coal-fired plant. The PSC could reduce the risk to a utility that proposes to construct a new IGCC plant by issuing a construction permit that grants the utility more flexibility regarding completion dates, the cost of construction, and the plant's anticipated capacity factor.

If a utility is considering a purchased power agreement that would allow it to acquire power from an IGCC merchant plant, the PSC's review of such a purchased power agreement would ordinarily occur only during the utility's rate cases. The PSC could reduce the risk that is embedded in the proposed purchased power agreement if the utility were to bring it to the PSC in advance, and the PSC ruled on the utility's ability to recover costs under the purchased power agreement, even if the plant were to produce less power than anticipated.

Action to Consider: PSC orders during construction or rate cases.

16. Create Tax Incentives

Wisconsin could create several types of tax incentives to encourage IGCC production. Some are income-tax related, such as investment tax credits, production tax credits, and accelerated depreciation, while others are exemptions from sales, property or other taxes. These incentives come at a cost to the taxing unit and should be evaluated for their effectiveness before implementing. Wisconsin could also seek changes in federal law to expand federal tax incentives.

Possible action: New state or federal legislation.

17. Create Economic Development/Environmental Grants

States such as Ohio have created economic development grants to promote IGCC production. Most of these grants relate to economic development in rust belt or mining areas or coal-industry promotion. While these are not relevant factors for Wisconsin, the state could consider environmental grants in areas of the state approaching non-attainment. This would reduce the cost of IGCC for ratepayers but would have a corresponding state fiscal impact.

Action to Consider: New legislation.

RESEARCH AND DEVELOPMENT

18. Join the Midwest Regional Sequestration Consortium

DOE has created several regional partnerships for the purpose of studying carbon capture and sequestration. The Midwest Regional Sequestration Consortium is studying the potential for storing carbon dioxide in the coal and oil fields of southern Illinois. Wisconsin is currently a member of another regional partnership based in North Dakota. Since the closest carbon storage opportunities for Wisconsin lie in Illinois, Wisconsin could seek to join the Illinois-based partnership.

Action to Consider: Transfer membership from the Plains Carbon Dioxide Reduction Partnership to the Midwest Regional Sequestration Consortium.

19. Initiate a Study of Carbon Dioxide Transportation Possibilities

As mentioned above, the coal and oil fields of Illinois are the nearest location where carbon dioxide that is produced in Wisconsin might be stored. Moving carbon dioxide to such a location would require either a new pipeline or mobile tanks; part of the Midwest Regional Sequestration Consortium's work involves the installation of a carbon dioxide pipeline in Illinois that will be approximately 150 miles long.[110] Since the ability to sequester carbon dioxide is likely to be one of the advantages of IGCC facilities, Wisconsin could, on its own or in partnership with Illinois, initiate a carbon dioxide transportation study.

Action to Consider: Initiate a study of the methods of carbon dioxide transportation to Illinois.

20. Join FutureGen

FutureGen is a $1 billion research project sponsored by DOE, whose purpose is to produce electricity and hydrogen from coal with zero emissions. It is a demonstration of coal gasification, electricity generation, hydrogen production and carbon sequestration. DOE signed an agreement with the FutureGen Industrial Alliance to build this research project.

The FutureGen Alliance recently issued a request for proposals, from which it will select a site for the FutureGen project. Both Minnesota and Illinois are sponsoring sites.

Action to Consider: Wisconsin could require or encourage its utilities to become members of the FutureGen Alliance to gain research and development knowledge. The state could also lend its political support to another state's FutureGen site bid.

[110] Presentation by Robert Finley, Illinois State Geological Survey, to IGCC Study Group on February 10, 2006.

OTHER

21. Reconvene the Study Group

This is an early stage for IGCC development in the United States. Both the technology and the governmental initiatives will mature over time, and it may be appropriate for the PSC and DNR to reconvene the study group next year in order to monitor these developments.

Action to Consider: Hold further meetings of the study group in 2007.

22. Develop an IGCC Plant with a Consortium of Utilities

A number of Wisconsin utilities are currently deciding whether to add more baseload facilities to their fleet of generating plants. It appears that several of these utilities are considering their own plant. In order to spread the risk of the new IGCC technology, the PSC could direct Wisconsin's major electric utilities to do a feasibility study of siting a jointly-owned IGCC plant in the state.

Action to Consider: Open a PSC docket to study the feasibility of Wisconsin utilities building a jointly-owned IGCC plant.

Appendix A

The following is a partial list of supercritical plants within the U.S. All units listed were manufactured by Babcock and Wilcox, which is one of three major vendors. The other major vendors are Combustion Engineering and Foster Wheeler.

Utility	Station	Capability (MWe)	StartupYear
Cincinnati G&E/Dayton P&L/ AEP-Columbus Southern Power	Zimmer	1300	1990
AEP-Indiana & Michigan Power	Rockport 2	1300	1989
AEP-Indiana & Michigan Power	Rockport 1	1300	1984
AEP-Appalachian Power	Mountaineer	1300	1980
TU Electric - Generating Div.	Monticello 3	775	1977
AEP-Ohio Power/Buckeye Power	Cardinal 3	650	1977
AEP-Ohio Power	Gavin 2	1300	1975
Duke Power Company	Belews Creek 2	1100	1975
Dayton P&L/Cincinnati G&E/ AEP-Columbus Southern Power	J.M. Stuart 4	600	1975
AEP-Ohio Power	Gavin 1	1300	1975
Duke Power Company	Belews Creek 1	1100	1974
AEP-Appalachian Power	Amos 3	1300	1974
Detroit Edison Company	Monroe 4	800	1974
Kansas City Power & Light Co./ Kansas Gas & Electric Co.	La Cygne 1	844	1973
Detroit Edison Company	Monroe 3	800	1973
Tennessee Valley Authority	Cumberland 2	1300	1973
Cleveland Electric Illuminating	Eastlake 5	680	1973
Dayton P&L/Cincinnati G&E/ AEP-Columbus Southern Power	J.M. Stuart 3	610	1973
Tennessee Valley Authority	Cumberland 1	1300	1972
Detroit Edison Company	Monroe 2	800	1972
Ohio Edison	W.H. Sammis 7	600	1972
Detroit Edison Company	Monroe 1	800	1971
Dayton P&L/Cincinnati G&E/ AEP-Columbus Southern Power	J.M. Stuart 1	610	1971
Dayton P&L/Cincinnati G&E/ AEP-Columbus Southern Power	J.M. Stuart 2	610	1971
Arizona Public Service/Southern Cal Edison	Four Corners 5	800	1970
West Penn Power	Hatfield Ferry 2	575	1970
West Penn Power	Hatfield Ferry 1	575	1970

Utility	Station	Capability (MWe)	StartupYear
Cleveland Electric Illuminating	Avon Lake 9	680	1970
New England Power Co.	Brayton Point 3	643	1969
Tennessee Valley Authority	Paradise 3	1150	1969
Arizona Public Service/Southern Cal Edison	Four Corners 4	800	1969
Ohio Edison	W.H. Sammis 6	623	1969
AEP-Ohio Power	Muskingum 5	591	1969
AEP-Ohio Power/Buckeye Power	Cardinal 2	590	1968
Ente Nazionale per I'Energia Elettrica	LaSpezia	600	1967
AEP-Ohio Power/Buckeye Power	Cardinal 1	590	1966
AEP-Indiana & Michigan Power	Tanners Creek 4	580	1964
AEP-Appalachian Power	Sporn 5	450	1960
AEP-Indiana & Michigan Power	Breed 1	450	1960
AEP-Ohio Power	Philo 6	125	1957

Source: Babcock & Wilcox Company Supercritical (Once Through) Boiler Technology, by JW Smith of B&W, 1998.
Note: MWe is megawatts electric.

United States Environmental Protection Agency

EPA-430/R-06/006
July 2006

Final Report

Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies

FOREWORD

Currently, over 50 percent of electricity in the U.S. is generated from coal. Given that coal reserves in the U.S. are estimated to meet our energy needs over the next 250 years, coal is expected to continue to play a major role in the generation of electricity in this country. With dwindling supplies and high prices of natural gas and oil, a large proportion of the new power generation facilities built in the U.S. can be expected to use coal as the main fuel. The environmental impact of these facilities can only be minimized by innovations in technology that allow for efficient burning of coal, along with an increased capture of the air pollutants that are an inherent part of coal combustion.

EPA considers integrated gasification combined cycle (IGCC) as one of the most promising technologies in reducing environmental consequences of generating electricity from coal. EPA has undertaken several initiatives to facilitate and incentivize development and deployment of this technology. This report is the result of one of these initiatives and it represents the combined efforts of a joint EPA/DOE team formed to advance the IGCC technology. The various offices within DOE that participated in the development/review of this report were the Office of Fossil Energy, including the Clean Coal Office and the National Energy Technology Laboratory.

IGCC is a dynamic and rapidly evolving technology. The economic and environmental information related to IGCC and other advanced combustion systems is changing quickly. The data and analysis presented in this report is an evaluation of information available as of February 2006. The report provides a snapshot of conditions in a changing industry and makes technical and cost information for the IGCC technology available to environmental professionals belonging to Federal and state organizations and other stakeholders. Detailed comparisons of the IGCC and pulverized-coal technologies are also provided, enabling the reader to observe and compare the capabilities of these technologies in relation to each other. The overall goal of this effort is to develop and compile technical and economic information to be used in connection with the development of EPA's policies, as well as to provide technical support and information transfer to ensure effective implementation of environmental regulations and strategies. EPA believes it is useful to examine these technologies as part of an ongoing effort to evaluate IGCC and other advanced coal systems.

EPA REVIEW NOTICE

This report has been peer and administratively reviewed by the U.S. Environmental Protection Agency, and approved for publication. This publication provides technical and economic information to support the goals and purposes described in the report. The report does not establish, prescribe, or change any EPA policy or legal interpretation with respect to the regulation and permitting of IGCC or pulverized-coal facilities. Emissions limitations and permit conditions for such facilities should be determined by permitting authorities on the basis of applicable EPA and state regulations and the record in each permit proceeding. EPA retains the discretion to promulgate or amend regulations and policy concerning the control of emissions from such sources on the basis of this report and additional information or public comment in the record of an Agency action. Mention of trade names or commercial products in this publication does not constitute endorsement or recommendation for use.

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Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies

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ABSTRACT

The report presents the results of a study conducted to establish the environmental footprint and costs of the coal-based integrated gasification combined cycle (IGCC) technology relative to the conventional pulverized coal (PC) technologies. The technology options evaluated are restricted to those that are projected by the authors to be commercially applied by 2010. The IGCC plant configurations include coal slurry-based and dry coal-based, oxygen-blown gasifiers. The PC plant configurations include subcritical, supercritical, and ultra-supercritical boiler designs. Even though the ultra-supercritical design has not been applied in the U.S., it was included based on its commercial experience in Japan and Europe.

All study evaluations are based on the use of three different coals: bituminous, sub-bituminous, and lignite. In addition, the same electric generating capacity of 500 MW is used for each plant configuration. State-of-the-art environmental controls are also included as part of the design of each plant.

The environmental comparisons of IGCC and PC plants are based on thermal performance, emissions of criteria and non-criteria air pollutants, solid waste generation rates, and water consumption and wastewater discharge rates associated with each plant. The IGCC plants in these comparisons include NO_X and SO_2 controls considered viable for 2010 deployment. In addition, the potential for use of other advanced controls, specifically the selective catalytic reduction system for NO_X reduction and the ultra-efficient Selexol and Rectisol systems for SO_2 reduction, is also investigated.

The cost estimates presented in the report include capital and operating costs for each IGCC and PC plant configuration. Cost impacts of using the advanced NO_x and SO_2 controls are likewise included.

The report also provides an assessment of the CO_2 capture and sequestration potential for the IGCC and PC plants. A review of the technical and economic aspects of CO_2 capture technologies that are currently in various stages of development is included.

ACKNOWLEDGEMENTS

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EXHIBITS

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LIST OF ACRONYMS AND SYMBOLS

As	Arsenic
ASU	Air Separation Unit
bbl	Barrel
Be	Beryllium
BOP	Balance of Plant
Btu/kWh	British Thermal Units per Kilowatt Hour
C_2H_6	Ethane
$CaSO_3$	Calcium Sulfite
$CaSO_4$	Calcium Sulfate
CCPC	Canadian Clean Power Coalition
CCS	Carbon Capture and Storage
Cents/kWh	Cents per Kilowatt Hour
Cd	Cadmium
CH_4	Methane
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COE	Cost of Electricity
COPHAC	Compact Hybrid Particle Collector
COS	Carbonyl Sulfide
Cr	Chromium
CSC	Convective Syngas Cooler
CS-ESP	Cold Side Electrostatic Precipitator
daf	Dry Ash Free
DOE	Department of Energy
E&M	Energy and Material
EIA	Energy Information Administration
EPRI	Electric Power Research Institute
ESP	Electrostatic Precipitator
FF	Fabric Filter
FGD	Flue Gas Desulfurization
GE	General Electric
GtCO2	Giga tons of CO_2
H_2	Hydrogen
H_2O	Water
H_2S	Hydrogen Sulfide
H_2SO_4	Sulfuric Acid
HCl	Hydrochloric Acid
HF	Hydrofluoric Acid
Hg	Mercury
HHV	Higher Heating Value
HRSG	Heat Recovery Steam Generator
HS-ESP	Hot Side Electrostatic Precipitator
IC	Installed Cost
IDC	Interest during Construction
IGCC	Integrated Gasification Combined Cycle
kW	Kilowatt
lb/MMBtu	Pounds per Million British Thermal Units
lb/MWh	Pounds per Megawatt Hour

lb/TBtu	Pounds per Trillion British Thermal Units
LHV	Lower Heating Value
MDEA	Methyldiethanolamine
MMBtu/hr	Million British Thermal Units per Hour
MMBtu/lb	Million British Thermal Units per Pound
Mn	Manganese
MW	Megawatts (Electric)
N_2	Nitrogen
n/a	Not Applicable
NH_3	Ammonia
Ni	Nickel
NO_2	Nitrogen Dioxide
NO_x	Nitrogen Oxides
O_2	Oxygen
O&M	Operating and Maintenance
PAC	Powdered Activated Carbon
Pb	Lead
PC	Pulverized Coal
PM	Particulate Matter
ppmvd	Parts Per Million By Volume Dry
PS	Particulate Scrubber
psia	Pounds Per Square Inch Absolute
psig	Pounds Per Square Inch Gauge
RSC	Radiant Syngas Cooler
SCOT	Shell Claus Off-Gas Treatment
SCR	Selective Catalytic Reduction
SCS	Separate, Capture, and Sequester
SDA	Spray Dryer Absorber
Se	Selenium
Si	Silica
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
TCC	Total Constructed Cost
t/MWh	Tons per Megawatt Hour
TPC	Total Plant Cost
TRS	Total Reduced Sulfur
V	Vanadium
VOC	Volatile Organic Compounds
WL-FGD	Wet Limestone Flue Gas Desulfurization
$/kW	Dollars per Kilowatt
$/kWh	Dollars per Kilowatt Hour
$-kW-yr	Dollars per Kilowatt Year
$/MMBtu	Dollars per Million British Thermal Units
$/MWh	Dollars per Megawatt Hour
$/ton	Dollars per Ton

Executive Summary

This report compares the environmental impacts and costs of integrated gasification combined cycle (IGCC) and pulverized coal (PC) fired power generation plants. The fuels and feedstocks for each type of plant studied include bituminous, subbituminous, and lignite coals. The PC plant configurations include subcritical, supercritical, and ultra-supercritical boiler designs. A coal-water slurry feed type of gasifier (typified by the Texaco, now GE Energy technology) is selected for the bituminous and subbituminous feedstocks. A solid feed gasifier (such as the Shell technology) is used with lignite. The technology options included in the IGCC and PC plant designs are restricted to those that are projected by the authors to be commercially applied by 2010.

The power generation technologies and emission control systems examined in this report continue to evolve in response to changes in market considerations and regulatory requirements. The report is a snapshot of conditions in the changing industry as of February 2006. Additional information on IGCC power plants proposed for development can be found at http://www.netl.doe.gov/coal/refshelf/ncp.pdf (accessed on June 21, 2006), which shows 24 proposed coal-fired power plants using gasification technology. The report contents are intended to serve as a broad screening tool consistent with the scope of work and project criteria established with EPA. Plant and site specific assessments will require more detailed engineering studies prior to technical or economic decision making. Individual facility permitting requirements will depend on the applicable regulations and the record before the permitting authority.

Introduction

IGCC and PC fired boilers are the primary competing technologies for coal-based power generation. Fluidized bed combustion is another technology that may have a significant role in the industry.

Development and implementation of the IGCC technology is relatively immature compared with the PC technology that has hundreds or thousands of units in operation globally. While there are a number of gasification units installed at petroleum and chemical plants, there are only a few installations using coal to make electric power as the primary product.[1] Most of these IGCC installations were installed with government subsidies and have experienced technical and commercial problems common to the startup of new technologies. While many of the problems with operability and maintainability have been mitigated, successful application of the IGCC technology at additional commercial installations is needed to address any remaining concerns.

Relatively little research or commercial work has been done to investigate gasification of low rank coals, including subbituminous and lignite, for electric generation purposes. The existing IGCC plants use bituminous coals as feedstocks. Almost four million tons of subbituminous coal was gasified at the Louisiana Gasification Technology Inc. facility located at Dow's Plaquemine, Louisiana chemical plant under a Synfuels Corporation

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[1] Gasification Technologies Council World Gasification Survey Database, GTC website http://www.gasification.org/, accessed on February 21, 2006.

Contract from 1987 to 1995. However, without additional research or commercial experience with the gasification of low rank coals, it is difficult to compare the gasification technology development with low rank coals to that of bituminous coal.

The ultra-supercritical PC technology used in this study has a few operating installations in Japan and Europe. Thermal performance of plants using this technology may match or exceed IGCC performance. However, this technology has no commercial experience in the U.S. Therefore, for application in this country, the technology is considered unproven with potential technical and economic risks.

Advanced technologies are also being developed to improve the IGCC performance: new technologies for air separation and oxygen production, higher temperature gas cleaning methods, advanced gas turbines, and fuel cells. These technologies are being developed with the goal of raising thermal efficiency (higher heating value) to 50 - 60 percent. However, these advances are not likely to be accomplished in the 2010 timeframe for this study.

Power Generation Performance Comparison

Exhibit ES-1 summarizes the results of the performance estimates for the IGCC and PC plants. The IGCC plant performance in particular can vary depending on design and site specific factors, and the estimates for IGCC plants using subbituminous and lignite coals are based on process models which were developed with limited test or other actual data. The ultra-supercritical plant performance is also estimated from modeling calculations and values found in the literature.

Based on the data presented in Exhibit ES-1, the IGCC has significantly better thermal performance than the subcritical and supercritical PC plants in commercial applications within the U.S. The estimates developed from limited data on ultra-supercritical technology show its thermal performance to exceed that of the IGCC for bituminous and sub-bituminous coal cases.

Environmental Impact Comparison

With the exception of controls for CO_2, the control systems included in this report for reducing emissions of air pollutants from IGCC plants have been demonstrated at the two existing coal- and petroleum coke-based U.S. plants, and very similar systems are broadly used within the petroleum and chemical industries. The one remaining uncertainty appears to be the long-term, continuous operational proof for the generation industry that the emission control processes/equipment will work in the IGCC power generation context. Such proof would involve the use of coal, which has physical and chemical properties that tend to be much more heterogenic than refinery feedstocks, and the individual plant’s capability to generate baseload power without significant planned or unplanned interruptions. Partly this uncertainty is related to the more general lack of information about IGCC system upsets, reliability, and a well-engineered definition of redundancy requirements.

Compared with the PC plants, the IGCC more closely resembles a chemical plant than one for power generation. However, the power industry has incorporated and learned to use chemical processes for flue gas desulfurization, ammonia-based selective catalytic NO_X reduction processes, and a variety of water treatment and cleanup operations, so operation of an IGCC plant by the power industry is possible.

Based on the investigations conducted for this study, the IGCC technology can offer environmental advantages over the PC technologies in most emission areas. In addition to the reduced air emissions from the IGCC technology, the plants typically consume significantly less water and generate less solid waste in comparison to the PC technology, depending on coal properties and whether or not the solid waste streams are sold as industrial byproducts.

Exhibit ES-2 presents environmental impact estimates for the specific control technologies and coals utilized for various study cases. The estimates are based on literature review, including recent air permits and related documents, contacts with certain potential suppliers of the control technologies, and power generation modeling software. In general, the estimates represent typical control technology capabilities, which, in many cases, reflect the levels determined through best available control technology reviews conducted during the processing of air permits for recent power plants. In some cases, such as the subbituminous coal- and lignite-based IGCC plants, relevant air permit or operating data were not available. For these plants, information from other study sources, including vendor contacts, were used to develop the emission estimates.

The emissions and (in parallel) the removal capabilities are similar across the technologies and coals with the clearest distinction being that IGCC emissions are less than for PC plants for all pollutants. The IGCC cases studied do not include SCR for the syngas turbines. MDEA amine type acid gas cleaning is used along with a system for sulfur recovery. The PC plants have wet limestone flue gas desulfurization (WL-FGD) for the bituminous and lignite coals; a lime spray dryer absorber (SDA) desulfurization for the low-sulfur subbituminous coal; and all the PC plants have selective catalytic reduction (SCR) post-combustion NO_X controls.

The coal characteristics and types of control technologies used for the study plants influence the estimates in Exhibit ES-2. Changes in design assumptions can result in different estimates. In addition, new developments continue to take place for both the PC and IGCC technologies. Therefore, the data presented in this report are subject to change in the future.

The Exhibit ES-2 data also show the IGCC plants generating less solid waste than the PC plants. This comparison assumes that no waste is sold for industrial use, except for the relatively small amount of sulfur produced from IGCC. IGCC plants can also produce sulfuric acid as an alternative to sulfur, should the market conditions require this change.

All solid waste products from both PC and IGCC plants have varying degrees of potential for industrial use. Therefore, if it is assumed that these plants can sell some or all of their solid wastes, the differences between the amounts of solid waste generated as shown in Exhibit ES-2 would either reduce or be eliminated. The study investigations show that while approximately 24 percent of the PC plants were able to sell the gypsum produced from the wet FGD systems in 2004, only five percent were able to do so for the SO_2 wastes from the SDA systems. So, even though the industrial use of PC solid wastes is projected to increase in the future, it appears that a large number of such plants may not be able to sell their wastes. If an IGCC plant cannot sell its sulfur byproduct, it would have to be disposed of as a waste.

The study investigations included a comparison of major non-criteria and hazardous air pollutant emissions for the PC and IGCC technologies. In most cases, these emissions are heavily influenced by the concentration of impurities in the coal being used. Therefore, emissions of certain pollutants can vary over a wide range, depending on the coal characteristics. The estimates of the emissions of non-criteria and hazardous air pollutants are presented within the report in Exhibits 3-10, 3-11, 3-13, 3-14, 3-15, and 3-26.

Industry and government organizations have recently begun considering the application of the SCR technology to reduce NO_X from syngas-fired turbines at IGCC plants. Section 4 includes a topical study of the issue. Industry is reluctant to install SCR units because of impacts on the overall operation, performance uncertainties and marginal cost. The study estimated a cost of $7,290 to $13,120 per ton of NO_X removed based on the difference between 15 parts per million by volume, dry basis (ppmvd) emissions with syngas dilution combustion controls, and three ppmvd after the SCR is added. The wide range of cost estimates results from uncertainty for the degree of sulfur control installation required to operate the catalytic NO_X control technology.

The use of a SCR with the coal-based IGCC synthesis gas-fired turbine combined cycle system has no commercial operating experience and is still evolving, which makes the evaluation difficult and necessarily limited to the present level of understanding and criteria defined for the study. SCR performance and the quality of the synthesis gas going to the turbine are issues that are being continually examined to determine the limits of contaminants in the synthesis gas, especially sulfur, which causes fouling in the downstream heat recovery steam generator. The technology to remove sulfur from the synthesis gas and the removal requirement strongly impacts costs and introduces the major uncertainty about cost estimates. A second major economic uncertainty is the SCR catalyst life and replacement costs over time.

Also, the SCR operation uses ammonia as the means to reduce NO_X emissions, and depending on how the SCR is operated some ammonia will be released (termed “ammonia slip”) to the atmosphere and is a pollutant. The methods to balance NO_X reduction and ammonia slip in the presence of sulfur in the flue gas and thus minimize total emission impacts are not yet well defined for the IGCC technologies. Despite the present uncertainties, and perhaps as an indicator of future installations, it is noted that the "reference" IGCC plant being engineered by GE Energy and Bechtel Corporation includes SCR[2]. In addition, certain recently filed or amended IGCC permit applications propose use of SCR technology. These applications are not covered in the report, since the information on the applications became available after the study investigations were completed.

Cost and Availability Comparisons

Cost and availability are issues of uncertainty for the IGCC technology. Even given higher thermal efficiency and lower emissions, the cost and availability differences between IGCC and PC plants continue to be a major hurdle to commercial applications. While the differences in cost estimates for new plants reported by several sources are not that great, less than $100 per kilowatt in some cases, the actual cost disparities for IGCC demonstration facilities have been much greater. The IGCC estimates presented here are for plants that assume commercial performance, and unfortunately the cost for the first generation of plants is bound to be more than for the "N^{th} plant". Similarly, the availability of the currently operating IGCC plants has been around 80 percent (higher availability levels were achieved only by operating the combined cycle portion of the plant on natural gas or oil). These plants were designed with single-gasifier trains and it is expected that the future commercial facilities, designed with a spare gasifier train, would achieve availability levels of 85 percent and higher. In comparison, the subcritical and supercritical PC can generally achieve greater than 90 percent availability levels.

Capital and annual operating costs estimated for the plants are shown in Exhibit ES-3. While the capital costs for IGCC plants are higher than the costs for all three PC plant configurations, there are only small differences between the operating costs for all plants. Further cost details and discussion of the estimating basis and methodology are in Appendix A. The risk and uncertainty issues noted for the technologies' performance estimates apply equally to the cost estimates. Only limited information is available from operating plants showing the impact of coal quality on the IGCC and PC generation technologies. Even conceptual engineering work is much less available for IGCC plants using low rank coals than for the plants using bituminous coal.

The costs reported here are derived from recent literature and experience with similar PC and IGCC studies conducted by Nexant. References for the cost data are noted in Appendix A of the report. New, study-specific cost estimates were not within the scope of the current EPA/DOE assessment, which is focused on environmental impacts of the modeled operations. As a general statement, the cost data is from U.S. DOE, the Electric Power Research Institute (EPRI), and international publications. These costs were examined and revised to reflect a 4th Quarter 2004 price and wage level and the nominal plant capacity of 500 MW.

Accounting for the variability in the overall scope of each plant using different technologies and three ranks of coal adds another element of cost (and performance) uncertainty. The results presented in the report again utilize the review and adjustment of

[2] Gas Turbine World, Sept – Oct 2005 Volume 35 Number 4; "IGCC Closing the $/kW Cost Gap".

several data sources to estimate the costs associated with these variables. If the cost uncertainty is to be reduced, a more detailed engineering and design project would be required with site- and technology-specific criteria.

Carbon Dioxide Capture and Sequestration

The IGCC technology has received renewed attention from the perspective of greenhouse gas issues and carbon management. Section 5 contains a more detailed discussion of carbon management technologies. Applications of such technologies exist in industries other than power sector. A significant amount of research and development work is being done to address the technical and economic feasibility issues pertaining to the commercial application of these and other emerging technologies to IGCC and PC plants. Demonstration of the feasibility of permanently sequestering CO_2 in underground geological formations is part of these efforts.

The currently available carbon management technologies for IGCC are much more cost effective than similar technologies for removing CO_2 from PC plant flue gases. The major performance and economic impacts of applying these technologies to IGCC and supercritical PC plants for achieving approximately 90 percent CO_2 capture are reported as follows:

	IGCC	**Supercritical PC**
Net plant output (pre CO_2 capture), MW	425	462
Plant output derating, %	14	29
Heat rate increase, %	17	40
Total capital cost increase, %	47	73
Cost of electricity increase, %	38	66
CO_2 capture cost, $/ton	24	35

The above comparison highlights the potential advantage for IGCC to capture and sequester CO_2 at significantly lower costs than PC technologies.

Future Actions

Improvement of the knowledge database for PC and IGCC technologies, especially for a complete range of North American coals, will require substantially more detailed process engineering and coordination with the technology developers. The limited contacts with technology developers for this study confirmed their willingness to work with industry and government, but they were not prepared to provide detailed information without a complete design basis from which to work, and in some cases this work would have to be compensated.

Exhibit ES-1, Generation Performance Comparison

	Bituminous Coal				Subbituminous Coal			
Performance	IGCC Slurry Feed Gasifier	Sub-critical PC	Super-critical PC	Ultra Super-critical PC	IGCC Slurry Feed Gasifier	Sub-critical PC	Super-critical PC	Ultra Super-critical PC
Net Thermal Efficiency, % (HHV)	41.8	35.9	38.3	42.7	40.0	34.8	37.9	41.9
Net Heat Rate, Btu/kWh (HHV)	8,167	9,500	8,900	8,000	8,520	9,800	9,000	8,146
Gross Power, MW	564	540	540	543	575	541	541	543
Internal Power, MW	64	40	40	43	75	41	41	43
Fuel Required, lb/h	349,744	407,143	381,418	342,863	484,089	556,818	517045	460,227
Net Power, MW	500	500	500	500	500	500	500	500

	Lignite Coal			
Performance	IGCC Solid Feed Gasifier	Sub-critical PC	Super-critical PC	Ultra Super-critical PC
Net Thermal Efficiency, % (HHV)	39.2	33.1	35.9	37.6
Net Heat Rate, Btu/kWh (HHV)	8,707	10,300	9,500	9,065
Gross Power, MW	580	544	544	546
Internal Power, MW	80	44	44	46
Fuel Required, lb/h	689,720	815,906	752,535	720,849
Net Power, MW	500	500	500	500

Exhibit ES-2, Environmental Impact Comparison

	Bituminous Coal				Subbituminous Coal			
Environmental Impact lb/MWh	IGCC Slurry Feed Gasifier	Sub-Critical PC	Super-critical PC	Ultra Super-critical PC	IGCC Slurry Feed Gasifier	Sub-critical PC	Super-critical PC	Ultra Super-critical PC
NO_X (NO_2)	0.355	0.528	0.494	0.442	0.326	0.543	0.500	0.450
SO_2	0.311	0.757	0.709	0.634	0.089	0.589	0.541	0.488
CO	0.217	0.880	0.824	0.737	0.222	0.906	0.832	0.750
Particulate Matter[1]	0.051	0.106	0.099	0.088	0.052	0.109	0.100	0.090
Volatile Organic Compounds (VOC)	0.012	0.021	0.020	0.018	0.013	0.025	0.023	0.020
Solid Waste[3]	65	176	165	155	45	73	67	60
Raw Water Use	4,960	9,260	8,640	7,730	5,010	9,520	8,830	7,870
SO_2 Removal Basis, %	99	98	98	98	97.5	87[4]	87[4]	87[4]
NO_X Removal Basis[2]	15 ppmvd at 15% O_2	0.06 lb/MMBtu	0.06 lb/MMBtu	0.06 lb/MMBtu	15 ppmvd at 15% O_2	0.06 lb/MMBtu	0.06 lb/MMBtu	0.06 lb/MMBtu

NOTES:
1. Particulate removal is 99.9% or greater for the IGCC cases and 99.8% for bituminous coal, 99.7% for subbituminous, and 99.9% for lignite for the PC cases. Particulate matter emission rates shown include the overall filterable particulate matter only.
2. A percent removal for NO_X can not be calculated without a basis, i.e. an uncontrolled unit, for the comparison. Also, the PC and IGCC technologies use multiple technologies (e.g., combustion controls, SCR). The NO_X emission comparisons are based on emission levels expressed in ppmvd at15% oxygen for IGCC and lb/MMBtu for PC cases.
3. Solid Waste includes slag (not the sulfur product) from the gasifier and coal ash plus the gypsum or lime wastes from the PC system.
4. A relatively low SO_2 removal efficiency of 87% represents low subbituminous coal sulfur content of only 0.22%. Higher removal efficiencies are possible with increased coal sulfur content.

Exhibit ES-2, Environmental Impact Comparison, continued

	Lignite Coal			
Environmental Impact lb/MWh	IGCC Solid Feed Gasifier	Sub-Critical PC	Super-critical PC	Ultra Super-critical PC
NO_X (NO_2)	0.375	0.568	0.524	0.498
SO_2	0.150	0.814	0.751	0.714
CO	0.225	0.947	0.873	0.830
Particulate Matter[1]	0.053	0.114	0.105	0.100
Volatile Organic Compounds (VOC)	0.013	0.026	0.024	0.022
Solid Waste[3]	218	331	306	291
Raw Water Use	5,270	9,960	9,200	8,710
SO_2 Removal Basis, %	99	95.8[4]	95.8[4]	95.8[4]
NO_X Removal Basis[2]	15 ppmvd at 15% O_2	0.06 lb/MMBtu	0.06 lb/MMBtu	0.06 lb/MMBtu

NOTES:

1. Particulate removal is 99.9% or greater for the IGCC cases and 99.8% for bituminous coal, 99.7% for subbituminous, and 99.9% for lignite for the PC cases. The emission rates shown include the overall filterable particulate matter only.
2. A percent removal for NO_X can not be calculated without a basis, i.e. an uncontrolled unit, for the comparison. Also, the PC and IGCC technologies use multiple technologies (e.g., combustion controls, SCR). The NO_X emission comparisons are based on emission levels expressed in ppmvd at15% oxygen for IGCC and lb/MMBtu for PC cases.
3. Solid Waste includes slag (not the sulfur product) from the gasifier and coal ash plus the gypsum or lime wastes from the PC system.
4. A relatively low SO_2 removal efficiency of 95.8% represents low lignite sulfur content of only 0.64%. Higher removal efficiencies are possible with increased coal sulfur content.

Exhibit ES-3, Technology Cost Comparison

	Bituminous Coal				Subbituminous Coal			
Costs*	IGCC Slurry Feed Gasifier	Sub-critical PC	Super-critical PC	Ultra Super-critical PC	IGCC Slurry Feed Gasifier	Sub-critical PC	Super-critical PC	Ultra Super-critical PC
Total Plant Cost $/ kW	1,430	1,187	1,261	1,355	1,630	1,223	1,299	1,395
Total Plant Investment $/kW	1,610	1,303	1,384	1,482	1,840	1,343	1,426	1,526
Total Capital Requirement $/ kW	1,670	1,347	1,431	1,529	1,910	1,387	1,473	1,575
Annual Operating Cost $1,000s	27,310	27,700	29,000	30,400	29,700	28,300	29,600	31,100

	Lignite Coal			
Costs*	IGCC Solid Feed Gasifier	Sub-critical PC	Super-critical PC	Ultra Super-critical PC
Total Plant Cost $/ kW	2,000	1,255	1,333	1,432
Total Plant Investment $/kW	2,260	1,378	1,463	1,566
Total Capital Requirement $/ kW	2,350	1,424	1,511	1,617
Annual Operating Cost $1,000s	34,000	29,640	30,940	32,440

* All costs are based on 4th Quarter 2004 dollars.

Section 1 Process Design

Section 1 presents the design criteria and methodologies used in evaluating various processes and technologies discussed in this report.

1.1 Introduction

The U.S. Environmental Protection Agency (EPA) sponsored this study to evaluate and compare environmental impacts and costs of integrated gasification combined cycle (IGCC) and pulverized coal (PC) power plants. These estimated impacts and costs for the technologies will assist various government agencies to better understand the potential effects of rulemaking and regulatory actions on application of the technologies in practical, real-world conditions.

Results are based upon information collected in one of two ways. First, in-house Nexant software, experience with similar evaluations, and literature were used to estimate performance and costs of the two technologies. Second, equipment and process suppliers were contacted for updated information specific to the environmental control aspects of the plants. The suppliers' data were used to refine the first estimates and improve the performance and cost estimates of the environmental controls. Seeking new data from gasification technology developers was not within the scope of this report; it was judged that sufficient published and in-house data was available to assess gasification technology performance and cost.

1.2 Design Basis

The study examines five power generation technologies and three different coals. All the modeled power plants are sized for a net power generation of 500 MW. They are configured with equipment and processes that are judged available for deployment in power generation plants in the 2010 time period. The modeled plants include the following design features:

- IGCC plants with steam conditions of 1,800 psig and 1,000/1,000 ºF. The coal-water slurry feed type of gasifier represented by GE Energy (ex-ChevronTexaco) is used with two coals, and a solid feed gasifier such as Shell gasification is used with lignite.

- PC plants with subcritical steam conditions of 2,400 psig and 1,000/1,000ºF single reheat.

- PC plants with supercritical steam conditions of 3,500 psig and 1,050/1,050 ºF double reheat.

- PC plants with ultra-supercritical steam conditions of 4,500 psig and 1,100/1,100 ºF double reheat.

- Ambient conditions are 60 ºF dry bulb, 60% relative humidity, and sea level elevation. Heat rejection uses wet cooling tower technology.

Three coals were chosen by EPA for the study. The coal characteristics and ash mineral properties are shown in Exhibits 1-1a, 1-1b, and 1-2.

Exhibit 1-1a, Study Coal Proximate Analyses

Coal Property **Proximate Analysis**, Weight %	High-Sulfur Bituminous	Low-Sulfur Subbituminous	Lignite
Moisture	11.12	27.40	31.24
Ash	9.70	4.50	17.92
Volatile matter	34.99	31.40	28.08
Fixed carbon	44.19	36.70	22.76
Total	100.00	100.00	100.00

Exhibit 1-1b, Study Coal Ultimate Analyses

Coal Property, **Ultimate Analysis**, Weight%	High-Sulfur Bituminous		Low-Sulfur Subbituminous		Lignite	
	As Received	Dry Basis	As Received	Dry Basis	As Received	Dry Basis
Carbon	63.74	71.71	50.25	69.21	36.27	52.75
Hydrogen	4.50	5.06	3.41	4.70	2.42	3.52
Nitrogen	1.25	1.41	0.65	0.90	0.71	1.03
Oxygen	6.89	7.75	13.55	18.66	10.76	15.65
Sulfur	2.51	2.82	0.22	0.30	0.64	0.93
Ash	9.70	11.24	4.50	6.23	17.92	26.12
Moisture	11.12		27.40		31.24	
Undetermined	0.29		0.02		0.04	
Total	100.00	100.00	100.00	100.00	100.00	100.00
Higher heating value (HHV), Btu/lb	11,667		8,800		6,312	
HHV, KJ/kg	27,137		20,469		14,682	

Note: Dry Basis - calculated. Undetermined added to ash.

Exhibit 1-2, Mineral Analysis Data

Mineral Analysis, Weight %	High-Sulfur Bituminous	Low-Sulfur Subbituminous	Lignite
Silica	43.95	33.40	56.96
Ferric oxide	22.79	5.20	3.49
Alumina	20.89	16.30	19.01
Titania	1.00	1.20	1.25
Lime	4.05	21.50	8.39
Magnesia	0.79	6.40	1.88
Sulfur trioxide	2.87	11.70	5.49
Potassium oxide	1.97	0.35	0.74
Sodium oxide	1.15	1.90	0.36
Phosphorus pentoxide	0.12	1.20	0.05
Undetermined	0.42	0.85	2.38
Total	100.00	100.00	100.00

The PC power plants are evaluated with each of the coals. The IGCC plants are similarly evaluated except the type of gasifier is dependent on the type of coal used.

The EPA design basis also specifies the criteria and non-criteria pollutants considered in the environmental assessment. The items are shown in Exhibit 1-3.

Exhibit 1-3, EPA Criteria and Non-Criteria/Hazardous Pollutants

Criteria Air Pollutants	Non-Criteria/Hazardous Air Pollutants	
Nitrogen Oxides (NO_X)	Mercury (Hg)	Manganese (Mn)
Sulfur Dioxide (SO_2)	Volatile Organic Compounds (VOC)	Cadmium (Cd)
Carbon Monoxide (CO)	Chlorides (HCl)	Chromium (Cr)
Particulate Matter (PM_{10})	Fluorides (HF)	Formaldehyde
Fine Particulate Matter ($PM_{2.5}$)	Sulfur Trioxide (SO_3)	Nickel (Ni)
Lead (Pb)	Hydrogen Sulfide (H_2S)	Silica (Si)
	Sulfuric acid	Selenium (Se)
	Ammonia (NH_3)	Vanadium (V)
	Arsenic (As)	Total Reduced Sulfur (TRS)
	Beryllium (Be)	Reduced sulfur compounds

Section 2 describes the major processes and components of various IGCC and PC plant configurations included in this report.

2.1 Process Description

The PC and IGCC plants used for the study are relatively “conventional” plants. With the exception of the ultra-supercritical PC technology, the equipment is commercial or near-commercial. (Ultra supercritical technology with conditions similar to the study criteria is deployed in Japan and Europe to a limited extent. Major manufacturers are working to develop the technology for use in the U.S. Research is being pursued to increase the temperature beyond 1,100 ºF.) While the focus of the study is the environmental performance of the plants, a brief description of the plants is provided to illustrate the overall plant configuration. In general, Sections 2 and 3 of the study describe technologies that can be commercially deployed. Sections 4 and 5 describe technologies that can still potentially be deployed but have no direct commercial experience with the power generation technologies considered in this study. Exhibit 2-1 lists major features of each type of plant with emphasis on their differences.

Exhibit 2-1, Summary of Plant Design Features

Plant Features	Pulverized Coal Plants	Gasification Combined Cycle Plants
Generation Method	All coals, boiler and steam turbine cycle.	A. Bituminous and subbituminous coals, coal slurry feed gasifier combined cycle. B. Lignite coal, solid feed gasifier combined cycle.
Particulate Control	All coals, fabric filter baghouse.	All coals, high temperature metal filters. (The wet processing of the gas cleaning process adds to particulate removal downstream of the filters.)
NO_X Control	Combustion controls & SCR.	All coals, combustion controls with nitrogen dilution.

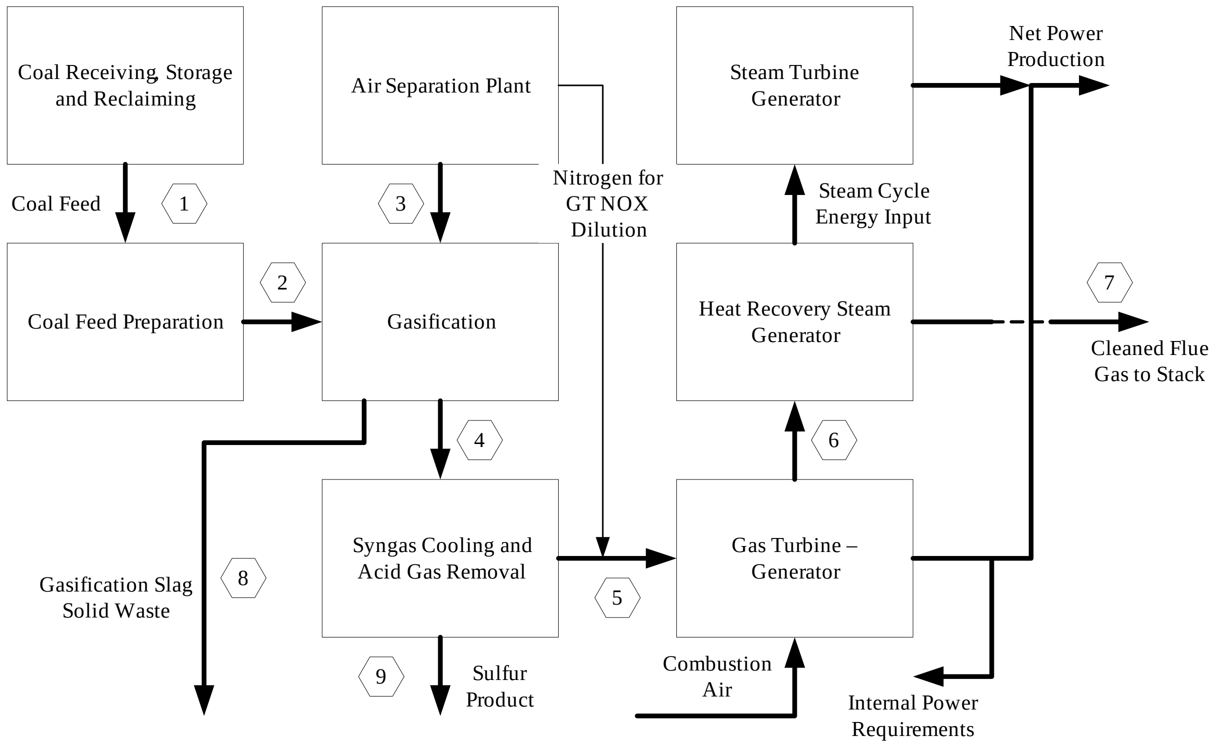
Plant Features	Pulverized Coal Plants	Gasification Combined Cycle Plants
SO_2 Control	A. Bituminous and lignite coals, wet limestone flue gas desulfurization and production of gypsum. B. Subbituminous coal, lime spray dryer desulfurization followed by fabric filter baghouse and production of solid waste containing SO_2 reaction products and ash	All coals, methyldiethanolamine (MDEA) gas cleaning and production of elemental sulfur.

In addition to the controls listed in Exhibit 2-1, the PC plants firing bituminous coal and lignite are equipped with a wet electrostatic precipitator (ESP) for controlling emissions of sulfuric acid mist. The cobenefits of a wet ESP may also include removal of other pollutants, such as particulate matter and mercury. The emissions and generation performance estimates presented for PC and IGCC plants are for "normal" operating conditions. All the plants will require a startup operation, often using oil or natural gas and generating emissions different from baseload design operations. Conditions may also change during shutdown operations and certainly during unplanned operating upsets where the plant or components may need to be shutdown or operated off-design without notice. Emissions from off-design operations are not addressed in this report. In addition, only the air emissions associated with the exhaust from the main stack are addressed for each plant. Other sources of air emissions, such as from an auxiliary boiler or IGCC flare, have not been reported, since they are considered to be minor in comparison to the main stack emissions.

2.1.1 IGCC Plants

The IGCC power plant processes are summarized in this section; more detailed descriptions of the environmental control systems are presented later. Exhibit 2-2 illustrates the nominal 500 MW IGCC plant. The material and energy balance tables related to the numbered major flow streams are presented in Appendix C. As noted with the balance tables, the calculations are derived from Nexant's spreadsheet power plant model, and are used primarily to estimate plant performance across the technologies and three coal ranks. The emission results may not be exactly the same as provided in other parts of the report due to rounding, calculation differences and the use of other sources, mainly air permit data, to define the emissions.

Exhibit 2-2, Integrated Gasification Combined Cycle Block Diagram



It is worth noting that there are significantly more technical and installation differences between the alternative gasification and IGCC systems than for the PC plants. Some of the differences arise from the technology's relatively young level of commercial maturity; others from the varying technology developers' designs. For the present study the bituminous and subbituminous coals utilize a GE Energy (Ex-ChervonTexaco, Texaco) type of gasifier with coal/water slurry feed system. The unit includes radiant and convective heat recovery for higher efficiency operations and uses two-50% gasification trains. For the high moisture lignite coal, a solid feed Shell type of gasifier was selected, also with two-50% gasification trains. All the plants use an F-type gas turbine in the combined cycle operation.

Performance data for bituminous coal- and petroleum coke-fueled IGCC plants is widely available in the literature and from previous Nexant work[3]. More limited up-to-date data is available for low-rank coal gasification. The best sources of data are, of course, the technology providers. However, creation of data at the level of detail that the major gasification developers feel necessary to support their technologies is costly and time consuming. For the present work, data from Nexant experience and the literature were

[3] Gasification Plant Cost and Performance Optimization Project, U.S. DOE/NETL Contract No. DE-AC26-99FT40342, September 2003, prepared by Nexant, Inc., Bechtel Corporation and Global Energy.

the basis for performance estimates. As will be discussed later, the IGCC environmental control areas were evaluated by contacting potential suppliers for those components.

The performance levels reported in this study for various IGCC plant configurations are based on current technologies. Based on ongoing research and development activities, a potential exists for considerable improvements in the IGCC performance levels. The goals of these activities are to achieve overall plant thermal efficiency levels of 45 to 50 percent by 2010 and 50 to 60 percent by 2020[4].

In gasification's simplest form, coal is heated and partially oxidized with oxygen and steam and the resulting synthesis gas, or syngas (primarily hydrogen and carbon monoxide), is cooled, cleaned and fired in a gas turbine-generator. Oxygen for the gasifier is produced in an air separation plant. The gas turbine exhaust goes to a heat recovery steam generator (HRSG), producing steam that is sent to a steam turbine-generator. Power is produced from both the turbine-generators. It is generally accepted that the IGCC system, by removing most pollutants from the syngas prior to combustion, is capable of meeting more stringent emission standards than PC technologies. It is also generally accepted that IGCC costs are higher and more uncertain than for PC plants, because PC technology has been demonstrated at many more installations. At present, the IGCC system also has greater promise to incorporate CO_2 capture for sequestration without large cost and energy penalties.

There are many variations on the basic IGCC scheme, especially in the degree of process integration. Three major types of gasification systems are used today: moving bed; fluidized bed; and entrained flow. The figure from EPRI in Exhibit 2-3 shows major characteristics of the three gasifiers.[5]

In a moving-bed gasifier, a bed of crushed coal is supported by a grate and the reactions between coal, oxygen, and steam take place within this bed. The gasifier operates at temperatures below the ash slagging temperature.

Fluidized-bed gasifiers also have a discrete bed of crushed coal. However, the coal particles are kept in a constant motion by the upward gas flow. The fluidized bed is maintained below the ash fusion temperature.

In entrained-flow gasifiers, finely pulverized coal particles concurrently react with steam and oxygen with very short residence time. These gasifiers operate at high temperature where the coal ash becomes a liquid slag. These units form the majority of IGCC project applications and include the coal/water-slurry-fed processes of GE Energy and ConocoPhillips, and the dry-coal-fed Shell process. A major advantage of the high-

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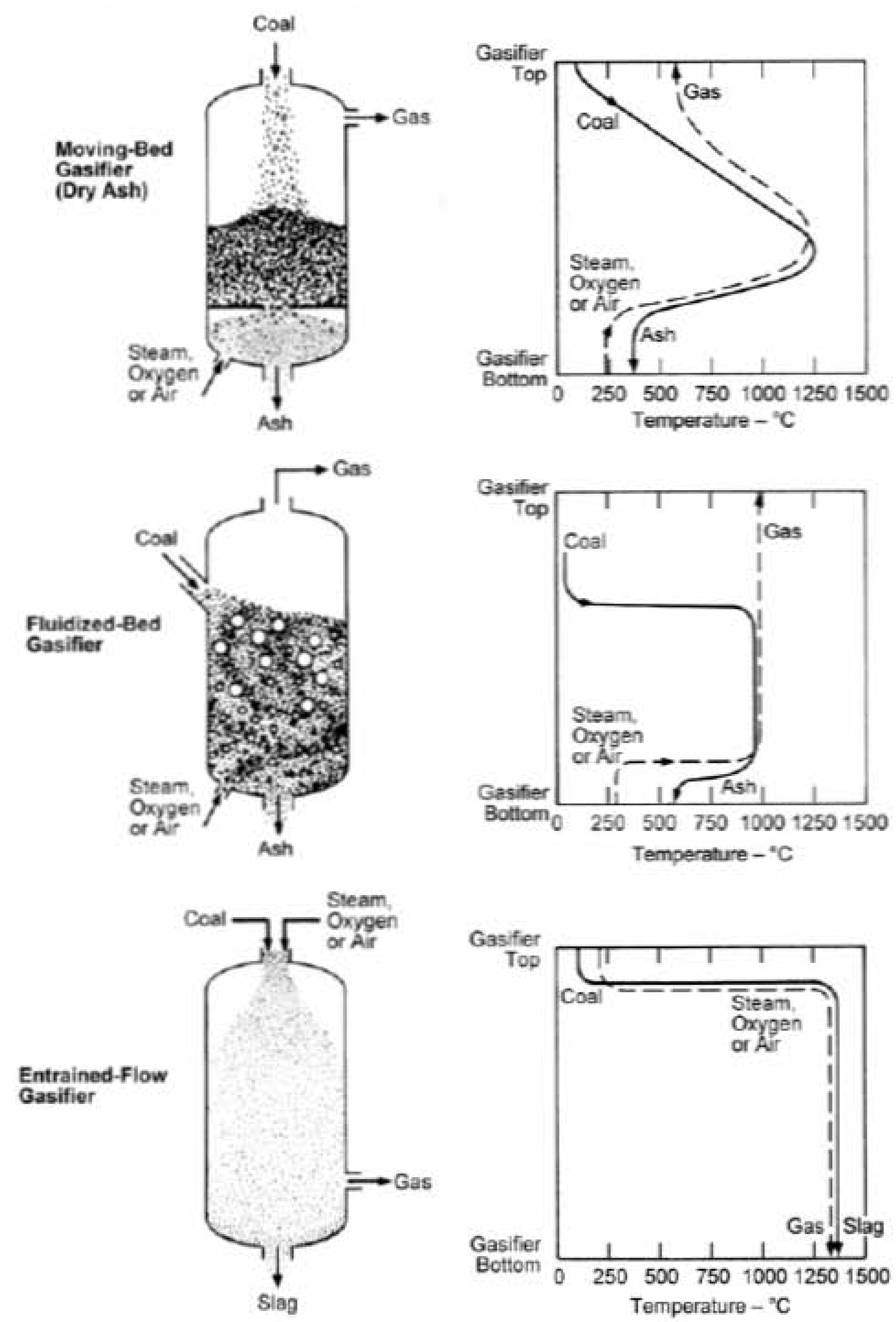
[4] H. Morehead, et al.,"Improving IGCC Flexibility through Gas Turbine Enhancement," Gasification Technologies Conference, October 4-5, 2004, Washington, DC.
[5] Neville Holt, "Gasification Process Selection – Trade-offs and Ironies", Gasification Technologies Conference, October 4-55, 2004, Washington, DC.

Exhibit 2-3, Major Gasification System Types



temperature entrained-flow gasifiers is that they avoid tar formation and its related problems.

Another variation in gasifier design involves use of air, instead of oxygen, to accomplish partial oxidation of fuel in a gasifier. This design eliminates the need for using an expensive air separator required for oxygen-blown gasifiers. The syngas produced from an air-blown gasifier has a lower calorific value, compared to the syngas produced from an oxygen-blown gasifier. Research and development work done both in the U.S. and Japan shows certain cost and performance advantages associated with the use of air-blown gasifiers, especially for low-rank coals. An IGCC demonstration plant, partially funded by DOE and using an air-blown Transport gasifier design, has recently been proposed to be built in Florida.[6]

All of the currently operating IGCC plants utilize oxygen-blown, entrained-flow gasifier designs. Therefore, this gasifier design is used for the IGCC plants in the present study.

IGCC operations have environmental benefits compared to PC units. Gasification occurs in a low-oxygen environment and the coal's sulfur converts to hydrogen sulfide (H_2S), instead of SO_2 as it does in the PC flue gas. The H_2S from gasification can be more easily captured and removed than the SO_2 in PC flue gas. Removal rates of 99% and higher for H_2S have been obtained with petrochemical industry cleanup technologies.[7]

NO_X emissions are an issue of special importance in the study of IGCC technology. Due to high flame temperature, the syngas can generate high NO_X emissions in the exhaust. However, IGCC units can be configured to operate with low NO_X emissions by saturating the syngas with steam or using nitrogen from the oxygen plant to dilute the fuel in the combustor. The base cases in this study use nitrogen dilution and saturation to control NO_X. A special analysis is presented later in this report, which examines the potential for including a SCR control device to further decrease the NO_X emission. An advantage of adding extra mass from the water and nitrogen is that additional power is generated in the gas turbine and steam cycle.

The IGCC concept was first demonstrated at the Cool Water Project in Southern California from 1984 to 1989. There are currently two commercial-scale, coal-based IGCC plants in the U.S. and two in Europe. The U.S. projects were supported by the DOE's Clean Coal Technology demonstration program.

The 262 MW Wabash River IGCC repowering project in Indiana started operations in

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[6] "Demonstration of a 285-MW Coal-Based Transport Gasifier," Project Facts, May 2005, NETL/DOE Internet Site, http://www.netl.doe.gov/publications/factsheets/fact_toc.html, accessed 5/2/2006.

[7] Major Environmental Aspects of Gasification-Based Power Generation Technologies, Final Report by: Jay Ratafia-Brown, Lynn Manfredo, Jeffrey Hoffmann, & Massood Ramezan for National Energy Technology Laboratory, U.S. Department of Energy, December 2002.

1995 and uses the ConocoPhillips E-Gas gasification technology. The 250 MW Polk Power Station IGCC project in Florida started in 1996 and uses the GE Energy gasification technology. Both plants have operated on bituminous coals and petroleum cokes; no use of low-rank coal is known. These plants reported the following emission data on USDOE/NETL fact sheets[8, 9]

Wabash River

- SO_2 capture efficiency greater than 99%, or emissions below 0.1 lb per million Btu. An MDEA acid gas removal system is used at Wabash.
- NO_X emissions were 25 ppmvd at 15% O_2 (0.15 lb/MMBtu).
- Particulate emissions were below detectable limits. After experimenting with a ceramic filter, Wabash switched to metallic filters for particulate control. The wet downstream operations also remove any remaining solids from the syngas.
- CO emissions averaged 0.05 lb/MMBtu.

Tampa Electric Polk Power Station

- Sulfur removal was over 97%. An amine-based (MDEA + COS conversion) acid gas removal system is used. Sulfur recovery includes sulfuric acid production.
- NO_X emissions were 15 ppmvd at 15% O_2 (0.055 lb/MMBtu). Nitrogen injection is used to control NO_X.
- Particulates were 0.007 lb/MMBtu. Particulate removal is in a water-wash synthesis gas scrubber.
- CO emissions averaged 7.2 pounds per hour.

The Wabash River and Polk plants are low emission, coal-based power technologies. New IGCC technologies are forecast to achieve 99% or more sulfur removal[10], essentially total volatile mercury removal (greater than 90-95% removal[11]), and particulate emission levels of less than 0.015 lb per million Btu[12]. An IGCC plant will also produce less solid waste, and will use less total water than a PC plant. These emission levels of performance are likely to be available in the 2010 timeframe set for the study, but electric generation market conditions and financial/technical risk make their implementation by that time uncertain, especially with low-rank coals.

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[8] U.S. DOE Fact Sheet at Internet Site: http://www.netl.doe.gov/technologies/coalpower/cctc/summaries/tampa/tampaedemo.html, accessed 2/28/06.

[9] U.S. DOE Fact Sheet at internet Site: http://www.netl.doe.gov/technologies/coalpower/cctc/summaries/wabsh/wabashrdemo.html, accessed 2/28/06.

[10] Evaluation of Innovative Fossil fuel Power Plants with CO2 Removal, U.S. DOE/NETL and EPRI, Prepared by ParsonsEnergy and Chemicals Group, December 2000 – updated 2002.

[11] Major Environmental Aspects of Gasification-Based Power Generation Technologies, Final Report by: Jay Ratafia-Brown, Lynn Manfredo, Jeffrey Hoffmann, & Massood Ramezan for National Energy Technology Laboratory, U.S. Department of Energy, December 2002.

[12] R. Brown, et. al., "An Environmental Assessment of IGCC Power Systems," 19th Annual Pittsburgh Coal Conference, September 2002.

For this study, the design basis includes use of two gasifiers for each plant configuration. This is intended to result in a design that can provide commercially acceptable plant availability. Based on experience from existing IGCC installations, the plant availability goals can also be achieved by using a standby fuel, natural gas or oil, for the gas turbines, in lieu of two gasifiers. The disadvantages to this approach include increased operating costs due to the use of expensive standby fuels as well as increased NO_X emissions from the gas turbines, which have been designed to handle syngas.

GE Energy Type Coal Slurry Feed Gasification

The coal is crushed and mixed with water to produce pumpable slurry that is 65 to 70 % coal by weight. Slurry is pumped into the gasifier with oxygen. The gasifier operates in a pressurized, down-flow, entrained design and gasification proceeds rapidly at temperatures in excess of 2,300 ºF. The raw gas is mainly composed of H_2, CO, CO_2, and H_2O. The hot syngas leaves the gasifier at the bottom and enters a radiant syngas cooler (RSC) where it is cooled to about 1,400 ºF, and in the process produces high pressure steam. The molten slag falls to the quench bath at the bottom of the cooler where it is solidified and removed with a lock hopper system. The syngas from the RSC is sent to a convective syngas cooler (CSC) for additional steam generation. The cooled gas is sent to the acid gas removal plant.

<u>Air Separation Plant</u>. A high-pressure cryogenic oxygen plant is used. The air for this plant is supplied in equal amounts from two sources: a bleed from the gas turbine compressor exhaust and an air stream supplied directly using a booster compressor. The gas turbine compressor bleed air preheats a nitrogen recycle stream sent to the gas turbine for NO_X control.

<u>Particulates</u>. Metal candle filters are used to remove ash particulates from the gasification process. Particulate emission from the IGCC process is usually termed negligible because the wet scrubbing devices employed with the acid gas cleaning and other operations remove all the measurable solids. Soot and other fine particulate may be emitted from auxiliary furnaces or other combustion devices if these are installed, and these emissions may need to be controlled.

<u>Gas Cooling/Heat Recovery/Hydrolysis/Gas Saturation</u>. The raw fuel gas is cooled in a series of heat exchangers and sent to acid gas removal. Any hydrogen chloride and ammonia is assumed to be in the condensate from these heat exchangers, which is then sent to an ammonia_strip unit for further treatment. A catalytic hydrolyzer converts the carbonyl sulfide to hydrogen sulfide. Heat recovery is used for generating stripping steam and boiler feed water heating.

<u>Acid Gas Removal (AGR).</u> The MDEA/Claus/SCOT process is used for acid gas removal and sulfur recovery. In the MDEA process, the cooled gas enters an absorber where it comes into_contact with the MDEA solvent. As it moves through the absorber, almost all of the H_2S and some of the CO_2 are removed. The solute-rich MDEA exits the absorber and is heated in a heat exchanger before entering the stripping unit. Acid gases from the

top of the stripper are sent to the Claus/SCOT unit for sulfur recovery. The lean MDEA solvent exits the bottom of the stripper and is cooled through several heat exchangers. It is then filtered and sent to a storage tank for the next cycle.

The Claus process occurs in two stages. In the first stage, about one-quarter of the gases from the MDEA unit are mixed with the recycle acid gases from the SCOT unit and are burned in the first furnace. The remaining acid gases are added to the second stage furnace, where the H_2S and SO_2 react in the presence of a catalyst to form elemental sulfur. The gas is cooled in a waste heat boiler and then sent through a series of reactors where more sulfur is formed. The sulfur is condensed and removed between each reactor. A tail gas stream containing unreacted sulfur, SO_2, H_2S, and COS is sent for processing in the SCOT unit.

Gas Turbine and Steam Cycle. A General Electric F type of gas turbine is partly integrated with the Air Separation Unit (ASU). From the turbine compressor exhaust, a bleed stream supplies half of the air needed for the ASU. The remainder of the compressor discharge air is used to combust the clean fuel gas. The ASU returns a nitrogen stream to the gas turbine combustor for NO_X control.

The steam cycle's major components include a heat recovery steam generator (HRSG), steam turbine, condenser, steam bleed for gas turbine cooling, recycle water heater, deaerator, and cooling tower for condenser cooling.

Balance of Plant (BOP). The BOP includes the following major components:

- Piping and Valves
- Ducting and Stack
- Waste Water Treatment
- Accessory Electric Plant
- Instrumentation and Control
- Buildings and Structures

Shell Type Solid Feed Gasification

The gasifier is a dry-feed, pressurized, oxygen-blown, entrained-flow slagging reactor. The coal is pulverized and dried prior to being fed into the gasifier. Nitrogen is used as the coal transport gas. Coal, oxygen and steam enter the gasifier through the burners. Raw fuel gas is produced from high temperature gasification reactions and flows upwardly with some entrained particulates. The high reactor temperature converts the remaining ash into a molten slag, which flows down the walls of the gasifier and passes into a slag quench bath. The fuel gas is quenched at the reactor exit with cooled recycled fuel gas to avoid sticky solids entering the raw gas cooler. The raw gas cooler further cools the gas and generates high-pressure steam for the steam cycle. Solids are recovered in the particulate filter and recycled back to the reactor.

Air Separation Plant (ASU). The ASU is similar to the operation described for the slurry-feed gasifier.

Particulates. Metal candle filters are used to remove ash particulates from the gasification process. Particulate emission from the IGCC process is usually termed negligible because the wet scrubbing devices employed with the acid gas cleaning and other operations remove all the measurable solids. Soot and other fine particulate may be emitted from auxiliary furnaces or other combustion devices if these are installed, and these emissions may need to be controlled.

Gas Cooling Section. The raw fuel gas from the particulate filter enters a gas-cooling section with several heat exchangers, a catalytic hydrolyzer, and a water scrubber. The raw fuel gas is cooled and sent to the hydrolyzer, which converts the carbonyl sulfide (COS) to hydrogen sulfide. The gas stream is further cooled before entering a water scrubber. Hydrogen chloride and ammonia are assumed to be in the scrubber water discharge, which is sent to a water treatment unit. About 30% of the cooled fuel gas stream is recycled to quench the hot raw fuel gas stream exiting the gasifier. The remaining fuel gas is sent to the cold gas cleanup for sulfur removal. The heat recovered is used for reheating the cleaned fuel gas and for heating boiler feed water in the steam cycle.

Cold Gas Cleanup Unit**.** The MDEA/Claus/SCOT process is used for cold gas cleanup and sulfur recovery and is similar to the earlier description.

Gas Turbine and Steam Cycle. The gas turbine is an F type machine similar to the previous case. The steam cycle major components include a heat recovery steam generator (HRSG), steam turbine, condenser, steam bleed for gas turbine cooling, recycle water heater, cooling tower, and deaerator.

Balance of Plant. The BOP includes the following major components:

- Piping and Valves
- Ducting and Stack
- Waste Water Treatment
- Accessory Electric Plant
- Instrumentation and Control
- Buildings and Structures

2.1.2 PC Plants

The pulverized coal plants are briefly described in this section. The overall scope for the PC plants includes the following major systems:

- Solids Material Handling

- Steam Generation
- NO_X Controls
- Particulate Collection
- Flue Gas Desulfurization, either a wet limestone FGD (WL-FGD) for the bituminous and lignite coals or a lime spray dry absorber (SDA) for the low-sulfur subbituminous coal
- Steam Turbine Generator
- Condensate and Feedwater Systems
- Balance of Plant

Simple block diagrams of the PC plants are shown as Exhibit 2-4 for plants firing the three coals. The major difference between plants is the type of flue gas desulfurization. Material and energy balance tables related to the block diagram stream numbers are presented in Appendix C. The environmental controls and performance are examined in more detail later. While not shown in the block diagrams, the PC plants firing bituminous coal and lignite are to be equipped with wet ESP units to enhance removal of acid mist.

Subcritical PC Plant

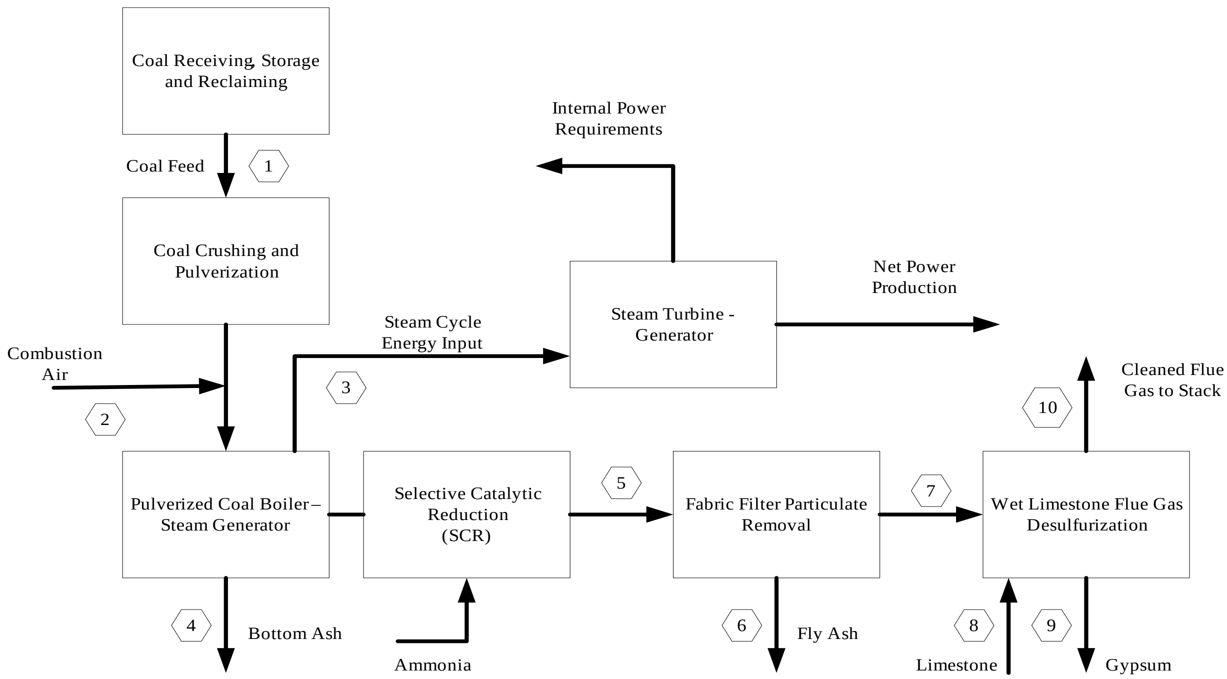
Solid Materials Handling. Solids handling includes receiving, conveying, storing and reclaiming coal, limestone or lime and the removal and disposal of coal ash and SO_2 reaction products. While there could be significant design differences between the three types of coals, the overall impact on generation and environmental performance would be small. For example, the lignite fuel is very likely to be used at a mine-mouth power plant and delivered by truck or conveyor. The bituminous and subbituminous coal options could be mine-mouth operations or not, with truck, conveyor, railroad, barge or some combination of delivery systems. Coal is reclaimed as needed from the storage; it is crushed and conveyed to short-term storage silos before being sent to the coal mills where it is pulverized for firing in the boiler.

Limestone for the WL-FGD unit is also delivered, stored and prepared on site. For the subbituminous coal plant with lime SDA SO_2 control, the lime is delivered, stored and slaked for use on site.

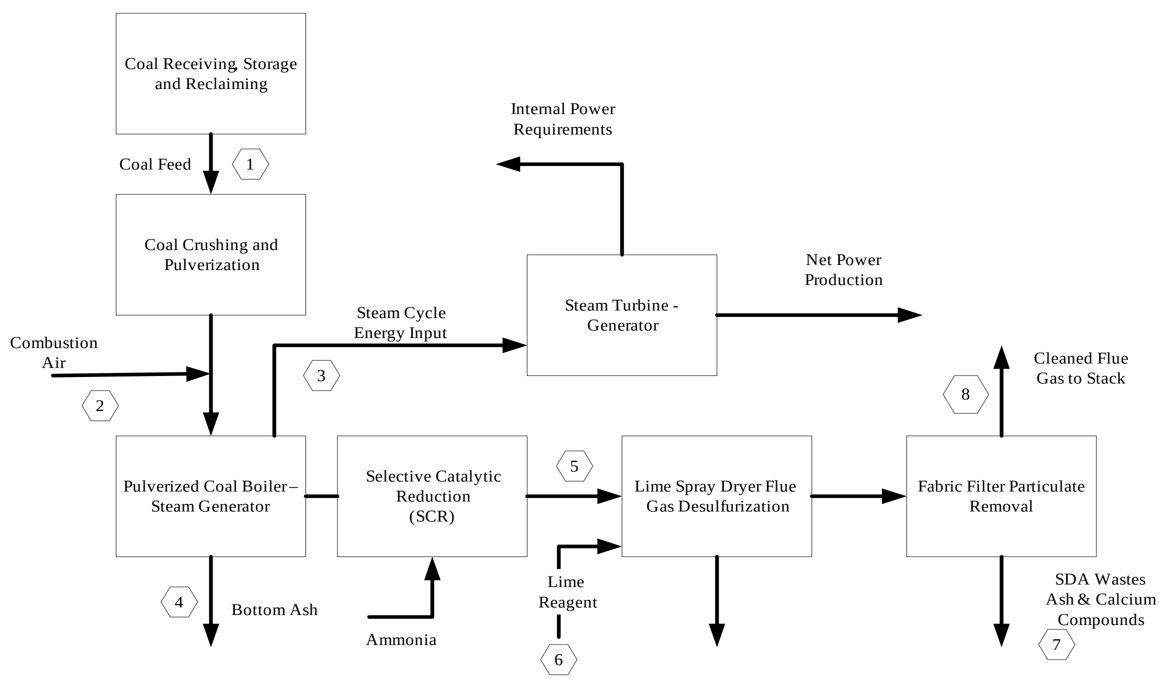
The ash handling system includes the equipment for conveying, preparing, storing, and disposing the fly ash and bottom ash produced on a daily basis by the boiler. Fly ash is conveyed to the fly ash storage silo from which it is loaded into trucks and sent to

Exhibit 2-4, Pulverized Coal Power Plant Block Diagrams

Bituminous and Lignite Coal-Fired Plant Diagram



Subbituminous Coal-Fired Plant Diagram



disposal. The bottom ash from the boiler is collected via a separate system and sent to disposal.

WL-FGD wastes (from processes using bituminous and lignite coals) are formed into gypsum and sent to dewatering and storage by placement in gypsum piles. Depending on market conditions and transportation costs, some plants may have the potential to produce salable gypsum and thus reduce their solid waste.

For the subbituminous coal and lime SDA sulfur control, the waste stream is a fine dry material that can be landfilled and disposed of with the coal fly ash. The potential for byproduct use of this desulfurization solid waste is limited, as discussed later in Section 3.6.

Steam Generation. This system includes the air handling and preheating systems, the coal burners, steam generation boiler and reheat, and soot and ash removal. The boiler is staged for low NO_X formation and is also equipped with a SCR as noted below. A drum-type steam generator is used to power a single-reheat subcritical steam turbine. The steam turbine conditions correspond to 2,400 psig and 1,000 °F at the throttle with 1,000 °F reheat.

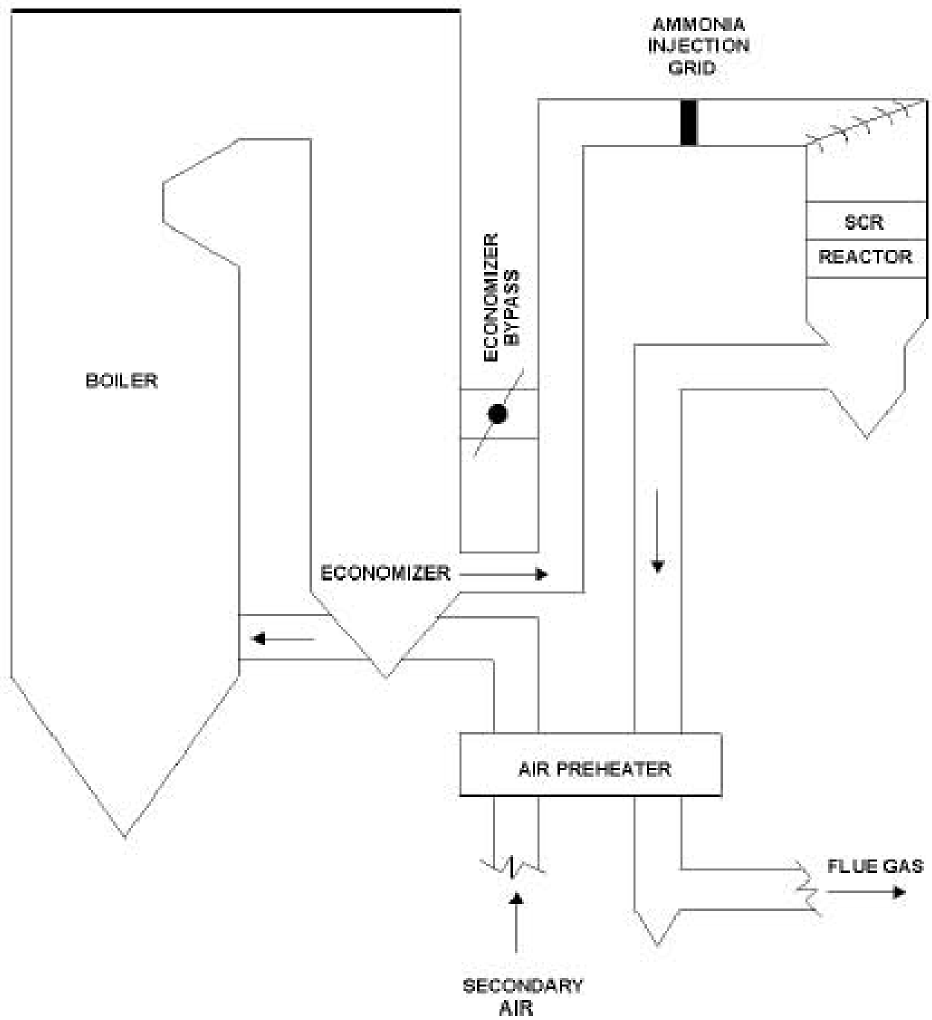
NO_X Controls. The NO_X controls for all three fuels consist of combustion controls and a selective catalytic reduction (SCR) system. The combustion controls include low-NO_X burners and overfire air. The SCR reactor is installed at the boiler economizer outlet, upstream of the air heater, as shown in Exhibit 2-5. These systems are described later in Section 3.

Particulate Collection. Particulate matter collection for all three coals is accomplished with the use of fabric filters. As an alternative, an electrostatic precipitator can also be used. However, a fabric filter was selected for this study, because it reduces reagent consumption when used in conjunction with a lime SDA system and it has better fine particulate and trace metal collection efficiencies.

Flue Gas Desulfurization. A WL-FGD is used with the high sulfur bituminous coal and the lignite. A lime SDA is used for the low-sulfur subbituminous coal. While the WL-FGD system is located after the fabric filter, the SDA unit is located downstream of the air preheater, followed by the fabric filter. The wet ESP used for the PC plants firing bituminous coal and lignite is located downstream of the WL FGD system (not shown in Exhibit 2-4).

Steam Turbine Generator. The turbine is tandem compound type, comprised of high pressure, intermediate pressure, two low pressure sections, and a final stage. The turbine drives a hydrogen-cooled generator. The throttle pressure at the design point is 2,400 psig. The exhaust pressure is 2.0/2.4 inch Hg in the dual pressure condenser. There are seven extraction points; the condenser is two shell, transverse, dual pressure type.

Exhibit 2-5, Example of SCR in a Pulverized Coal Boiler System



Condensate and Feedwater Systems. The condensate system moves condensate from the condenser to the deaerator, through the gland steam condenser and the low pressure feedwater heaters. The system consists of one main condenser; two 50 percent capacity condensate pumps; one gland steam condenser; four low pressure heaters; and one deaerator with a storage tank. The function of the feedwater system is to pump the feedwater from the deaerator storage tank through the high pressure feedwater heaters to the boiler economizer. Two 50 percent turbine-driven boiler feed pumps are installed to pump feedwater through the high pressure feedwater heaters.

Balance of Plant. The BOP includes the following major components.

- Steam Piping and Valves
- Circulating Water System with Evaporative Cooling Tower
- Ducting and Stack
- Waste Water Treatment

- Accessory Electric Plant
- Instrumentation and Control
- Buildings and Structures

Supercritical PC Plant

Solids Material Handling. The material handling systems are similar in scope to the subcritical plant discussion. Component sizes may be different because of higher efficiency of the supercritical plant (assuming equal generating capacity), but the impacts of this difference on performance and cost are small, especially compared to the impacts of specific site conditions, which can vary widely.

Steam Generation. The boiler is staged for low NO_X formation and is also equipped with a SCR. A once-through steam generator is used to power a double-reheat supercritical steam turbine. The steam turbine conditions correspond to 3,500 psig and 1,050°F at the throttle with 1,050°F at both reheats.

NO_X Controls. The controls used are the same as in the previous plant.

Particulate Collection. Fabric filters used are similar to the subcritical unit.

Flue Gas Desulfurization. The control technologies are the same as installed for the subcritical unit. Bituminous coal and lignite use WL-FGD systems preceded by the fabric filter, and the subbituminous coal uses a SDA followed by the fabric filter.

Steam Turbine Generator. The turbine consists of a very high pressure section, high pressure section, intermediate pressure section, and two low pressure sections, all connected to the generator by a common shaft. Main steam from the boiler passes through piping and valves and enters the turbine at 3,500 psig and 1,050 °F. The steam initially enters the turbine near the middle of the high-pressure span, flows through the turbine, and returns to the boiler for reheating. The first reheat steam flows through the reheat and enters the HP section at 955 psig and 1,050 °F. The second reheat steam flows through the reheat and enters the IP section at 270 psig and 1,050 °F. After passing through the IP section, the steam enters a crossover pipe, which transports the steam to the two LP sections. The steam is split into four paths which flow through LP sections exhausting downward into the condenser.

Condensate and Feedwater Systems and Balance of Plant. These operations are the same as discussed for the subcritical unit.

Balance of Plant. The BOP includes the following major components.

- Piping and Valves
- Circulating Water System with Evaporative Cooling Tower
- Ducting and Stack

- Waste Water Treatment
- Accessory Electric Plant
- Instrumentation and Control
- Buildings and Structures

Ultra-Supercritical Plant

The ultra-supercritical plant level of technology maturity differs from that of the two technologies discussed previously, and it is relatively rarely used, especially in North America. There are more than 500 supercritical PC plants throughout the world (primarily in Europe with a majority of them in the former Soviet Union and Japan) operating at pressures 3,500 psig and above and at temperatures up to 1,050 ºF. There are ultra-supercritical commercial plants in Japan and Denmark and all belong to the 1,100 ºF class. Two ultra-supercritical plants currently operated by Danish power companies are in the 250-400 MW range. One of these plants, the Evader unit, has steam conditions of 4,350 psig and 1,112 ºF giving an efficiency of 47 percent. The Kawagoe plant in Japan, consisting of two 700 MW units and operated by Chubu Electric since 1989, has steam conditions of 4,500 psig and 1,050 ºF with double reheat. Its efficiency is 45 percent. Currently the leading companies offering the 1,100 ºF class ultra-supercritical plants are mostly in Japan, such as Hitachi, IHI, MHI, and Mitsui. They are actively promoting the commercial use of this class of plants in the world, often in the form of joint companies, such as Babcock-Hitachi, and Mitsui-Babcock.

The available data for the Japanese and Danish plants do not state the basis for efficiency calculations, but the efficiencies are likely based on lower heating values of the fuels. Also, Denmark has banned coal and the units have been switched to accommodate natural gas and biomass fuels.

The relative immaturity of the ultra-supercritical technology also means that there are fewer sources of data, and the performance estimates made for this study are likely to have a wider variability than for the better known subcritical and supercritical technologies.

Solids Material Handling. The material handling systems are similar in scope to the other two plant descriptions. Component sizes may be different because of higher efficiency of the ultra-supercritical plant (assuming equal generating capacity), but the impacts of this difference on performance and cost are small, especially compared to specific site conditions, which can vary widely.

Steam Generation. The boiler is staged for low NO_X formation and is also equipped with a SCR. A once-through steam generator is used to power a double-reheat ultra-supercritical steam turbine. The steam turbine conditions correspond to 4,500 psig and 1,100°F at the throttle with 1,110°F at both reheats.

NO_X Controls. The controls used are the same as in the previous plants.

Particulate Collection. Fabric filters used are similar to the subcritical unit.

Flue Gas Desulfurization. The control technologies are the same as installed for the other PC technologies.

Steam Turbine Generator. The turbine consists of a very high pressure section, high pressure section, intermediate pressure section, and two low pressure sections, all connected to the generator by a common shaft. The ultra-supercritical conditions are 4,500 psig and 1,100 ºF with double reheat.

Condensate and Feedwater Systems and Balance of Plant. These operations are the same as discussed for the previous plants.

Balance of Plant. The BOP includes the following major components.

- Steam Piping and Valves
- Circulating Water System with Evaporative Cooling Tower
- Ducting and Stack
- Waste Water Treatment
- Accessory Electric Plant
- Instrumentation and Control
- Buildings and Structures

2.1.3 Process Maturity and Data Availability

The comparisons made for this study are intended to be on an equal basis for all the technologies. However, decision makers using the report should recognize that the technical and cost data come from different sources that may not be using exactly the same basis or criteria. The quantity of available data varies among the technologies and coals. It is also noted the IGCC technology is still developing (and advancing) while the PC technology is much more mature.

Except for the ultra-supercritical technology, the PC systems are well-defined and understood. Costs for PC plants can be estimated with relative certainty provided there is sufficient preliminary engineering to determine site and owner specific costs. The power generation industry is familiar with the PC plant operations and understands their reliability, load following and other operating features.

There are a large number of gasification units in operation globally too, but as noted before, there are very few gasification plants using coal to generate electric power as envisioned for IGCC installations. Most of the gasification units are at petroleum or chemical plants where special conditions favor the gasification of solids or liquids as part of an integrated process. Coal-based IGCC plants have uncertain costs and concerns with operating reliability. The power generation industry views the IGCC operations as "chemical plants", and has historically been reluctant to own and operate them. One of the concerns is the attainment of commercially acceptable levels of plant availability. The plant availability levels with existing single gasifier-train IGCC plants have been below the design availability targets of 85 percent[13]. It is expected that such targets can be met with the use of a spare IGCC train, which is the design basis for the IGCC plants in this study. In comparison, plant availability levels exceeding 90 percent can be achieved with the mature subcritical and supercritical PC technologies.

The ultra-supercritical plant data are less available than data for the IGCC technologies. A great amount of engineering and process design work has been done for gasification in the last few years with increasing emphasis on the potential for the technology to more effectively incorporate carbon management processes. For the ultra-supercritical technology, most of the work appears to be with advanced materials to construct the units to make them more attractive from cost and performance aspects. Much of the advanced PC work also is in Europe and Japan, where fuel prices have for a long time been relatively expensive, and increases in efficiency have greater impacts on costs of electric power than in the U.S. Except for the carbon management issue, plant efficiency in the U.S. has historically not been regarded as a major benefit that justifies the expenditure of additional capital for equipment or process improvements.

Another area of uncertainty and difference among the technologies is the refinery or chemical plant type of operations required by the IGCC technologies. While not absent from PC plants, operational upsets and off-design operations seem potentially more likely at the more complicated IGCC plants. Such upsets and off-design conditions can presumably be minimized by careful engineering, possibly installation of spare or special equipment, and a well-trained plant staff. The emissions of a well-run IGCC plant should be lower than for other coal systems, but there is an element of uncertainty because the long-term commercial experience does not yet exist, especially for the applications on low-rank coals.

[13] N. Holt,"Coal-Based IGCC Plant – Recent Operating Experience and Lessons Learned," Gasification Technologies Conference, October 5, 2004, Washington, DC.

Section 3 presents the results from the thermal and environmental performance assessments.

3.1 Power Generation Performance

The IGCC plant performance, based on the coal higher heating value (HHV), is summarized in Exhibit 3-1 for the bituminous and subbituminous coals. The slurry-feed type gasifier used for these coals is not well-suited to the high-moisture, high-ash lignite coal, and the subbituminous coal may be a difficult fuel to use for practical applications. High amounts of coal ash interfere with the radiant heat exchanger's ability to recover energy and generate steam. Also, high-ash slurry from the gasifier bottom is another source of heat losses. This has significant impact on the gasifier thermal efficiency. The Shell gasifier is more able to handle high-ash coals without heat loss penalties.

Gasification developers, such as GE Energy, have declined in the past to offer their technology for high moisture coals. On the other hand, ConnocoPhillips, who also offers a slurry-feed type system, has past subbituminous coal experience and would offer its gasifier for subbituminous coals in general. The Canadian Clean Power Coalition (CCPC) has examined low-rank coal gasification, but only reported summary level results.[14] In the CCPC summary, the efficiency for all the gasification cases was about 38%. It cannot be determined from this data whether, for example, the performance impacts of coal drying or increased oxygen demand were accounted for in the calculations. The CCPC study used GE Energy gasifiers for the bituminous and subbituminous coals, and Shell for the lignite. However, the Canadian subbituminous coal has less moisture, 20% compared to more than 27% for this study. Despite the uncertainty of low rank gasifier selection, the impacts on environmental issues would not be significantly different as all the IGCC technologies use very similar cleanup and control processes.

Exhibit 3-1, Integrated Gasification Combined Cycle Performance Estimates - Bituminous and Subbituminous Coals

GE-Energy Slurry Feed Gasifier and F-type Gas Turbine	Bituminous	Subbituminous
Net Thermal Efficiency (HHV), %	41.8	40.0
Net Heat Rate (HHV), Btu/kWh	8,167	8,520
Gross Power, MW	564	575
Internal Power, MW	64	75
Fuel required, lb/h	349,744	484,089
Net Power, MW	500	500

[14] G. Morrison, "Summary of Canadian Clean Power Coalition work on CO2 capture and storage," IEA Clean Coal Centre, August 2004.

Exhibit 3-2 presents summary performance data for the Shell solid feed type of gasifier and the lignite coal.

Exhibit 3-2, Integrated Gasification Combined Cycle Performance Estimates - Lignite Coal

Shell Solid Feed Gasifier and F-type Gas Turbine	Lignite
Net Thermal Efficiency (HHV), %	39.2
Net Heat Rate (HHV), Btu/kWh	8,707
Gross Power, MW	580
Internal Power, MW	80
Fuel required, lb/h	689,720
Net Power, MW	500

Exhibit 3-3 lists the typical consumers of internal power at the IGCC plants. The impact of the air separation plant and oxygen compression is highlighted. The coal preparation (thermal drying) component of the Shell technology is an area of performance and emission uncertainty. Limited public data is available to support engineering estimates, and the cost of detailed engineering needed to create and validate new data would be significant.

Exhibit 3-3, Typical IGCC Auxiliary Power Consumption Breakdown

Plant Component	% of Total Aux. Power	Plant Component	% of Total Aux. Power
Coal Handling and Conveying	0.7%	Humidification Tower Pump	0.2%
Coal Milling	1.5%	Humidifier Makeup Pump	0.1%
Coal Slurry Pumps	0.4%	Condensate Pumps	0.6%
Slag Handling and Dewatering	0.3%	Boiler Feedwater Pump	5.9%
Scrubber Pumps	0.6%	Miscellaneous Balance of Plant	2.0%
Recycle Gas Blower	1.2%	Gas Turbine Auxiliaries	1.2%
Air Separation Plant	47.1%	Steam Turbine Auxiliaries	0.4%
Oxygen Boost Compressor	24.1%	Circulating Water Pumps	3.6%
Amine Units	2.6%	Cooling Tower Fans	2.2%
Claus/TGTU	0.2%	Flash Bottoms Pump	0.1%
Tail Gas Recycle	2.8%	Transformer Loss	2.2%

The high amount of ash (slag) in lignite makes it unsuitable for GE Energy's entrained flow gasifier, because heavy slagging of the radiant heat exchanger slows heat removal and exchange. Also, the need for high ash content slurry to be removed from the bottom of the gasifier which retains significant heat energy is another major source of heat loss. These two factors have significant impact on the thermal efficiency of the gasifier and overall IGCC plant. Although the GE Energy gasifier can handle high moisture coal, the efficiency loss from the ash content of lignite is significant enough to make it unattractive.

The Shell gasifier has a refractory-lined water wall for syngas heat removal which can handle high loading of ash and still be effective in heat transfer. There is no significant loss in efficiency in Shell gasifier.

Greater details of energy and material balances for the IGCC plants are included in Appendix C of this report.

Exhibits 3-4, 3-5, and 3-6 present summary performance data for the PC units and the three coals.

Exhibit 3-4 Subcritical Pulverized Coal Unit Performance Estimates

Subcritical PC	Bituminous	Subbituminous	Lignite
Net Thermal Efficiency, % HHV	35.9	34.8	33.1
Net Heat Rate, Btu/kWh (HHV)	9,500	9,800	10,300
Gross Power, MW	540	541	544
Internal Power, MW	40	41	44
Fuel required, lb/h	407,143	556,818	815,906
Net Power, MW	500	500	500

Exhibit 3-5 Supercritical Pulverized Coal Unit Performance Estimates

Supercritical PC	Bituminous	Subbituminous	Lignite
Net Thermal Efficiency, % HHV	38.3	37.9	35.9
Net Heat Rate, Btu/kWh (HHV)	8,900	9,000	9,500
Gross Power, MW	540	541	544
Internal Power, MW	40	41	44
Fuel required, lb/h	381,418	517,045	752,535
Net Power, MW	500	500	500

Exhibit 3-6 Ultra Supercritical Pulverized Coal Unit Performance Estimates

Ultra Supercritical PC	Bituminous	Subbituminous	Lignite
Net Thermal Efficiency, % HHV	42.7	41.9	37.6
Net Heat Rate, Btu/kWh (HHV)	8,000	8,146	9,065
Gross Power, MW	543	543	546
Internal Power, MW	43	43	46
Fuel required, lb/h	342,863	460,227	720,849
Net Power, MW	500	500	500

Greater details of energy and material balances for the PC plants are included in Appendix C of this report. Exhibit 3-7 shows the typical auxiliary power consumers at the PC plants.

Exhibit 3-7, Typical PC Plant Auxiliary Power Consumption Breakdown

Plant Component	% of Total Aux. Power	Plant Component	% of Total Aux. Power
Coal Handling and Conveying	1.3%	Precipitators	3.4%
Limestone Handling & Reagent Preparation	3.2%	FGD Pumps and Agitators	11.9%
Pulverizers	6.4%	Condensate Pumps	2.0%
Ash Handling	5.7%	Boiler Feed Water Pumps	9.2%
Primary Air Fans	4.2%	Miscellaneous Balance of Plant	6.9%
Forced Draft Fans	3.3%	Steam Turbine Auxiliaries	1.4%
Induced Draft Fans	17.4%	Circulating Water Pumps	12.2%
SCR	0.3%	Cooling Tower Fans	7.1%
Seal Air Blowers	0.2%	Transformer Loss	3.9%

3.2 Integrated Gasification Combined Cycle Emissions

Emission controls for IGCC systems are described extensively in several of the references included elsewhere in this report. For most of the conceptual design studies, emissions are assumed to be equal to a regulation or otherwise selected standard. Brief summaries of the emission controls are presented in this report, which, as noted, focuses on estimates for typical emission reduction capabilities available with state-of-the-art versions of these controls. The emission estimates reflected below are provided for informational purposes only. Publication of such estimates in this report does not establish the estimates as emissions limitations for any source or require that such estimates be used as emissions limitations in any permit. Emission limitations and permit conditions should be determined by permitting authorities on a case-by-case basis considering applicable EPA and State regulations and the record in each permit proceeding.

Particulates

Solid particulates from the gasifier must be removed prior to downstream cleanup processes and syngas combustion. Solids removal is accomplished with metal filters followed by wet scrubbing. The removal of the solids as dry materials with the upstream filter minimizes dewatering and waste disposal issues. The scrubbers remove ammonia, chlorides, and other trace organic and inorganic components from the synthesis gas. The scrubber reject (blowdown) stream is flashed to a vapor and disposed of in a high temperature furnace. The remaining slurry goes to a solid-liquids separation step before disposal.

Acid Gas Cleanup/Sulfur Recovery

After removal of the particulates, the synthesis gas is further cleaned in preparation for combustion in the gas turbine. Acid gas cleanup processes similar to those widely applied in the petroleum and chemical industries are used for the IGCC plants. Commercial alternatives for IGCC acid gas cleaning are the chemical solvent processes based on amines and physical solvent-based processes. The aqueous methyldiethanolamine (MDEA) is used in this study. The MDEA processes are preceded by carbonyl sulfide (COS) hydrolysis units to convert the COS to H_2S. This allows more total sulfur removal. Selexol™ (dimethylether or polyethylene glycol) and Rectisol™ (cold methanol) are examples of physical solvents. The physical solvent technologies are commonly used in the chemical or petroleum industries when deep sulfur removal is needed for products or downstream processes. In one coal-based application, Rectisol process has removed greater than 99.9% sulfur from syngas[15]. The physical solvents are examined later in the study for use with SCR and NO_X reduction.

For the study, the acid gas removal process uses an amine solvent, MDEA, which chemically reacts with the H_2S and CO_2. The reacted amine is sent to a stripper where heat (steam) is used to separate the gases and regenerate the MDEA for recycle to the cleaning process. Acid gas cleanup processes are commercial and widely used by the petroleum and chemical industries. Sulfur removal and recovery approaches 100%, with 99% removal efficiency assumed for this study. Discussions with the MDEA and acid gas removal suppliers confirm that the level of sulfur removal is very much an economic

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[15] M. Rutkowski, et al., "The Cost of Mercury Removal in an IGCC Plant," Gasification Technologies Public Policy Workshop, October 1, 2002, Washington, DC.

tradeoff between the surface area of absorber materials, amine recirculation and stripping rates and sulfur removal. There are many site- and coal- specific factors that will impact the MDEA process details and costs, and detailed engineering is required for the MDEA system to be fully specified. The 99% removal value selected for the study is consistent with inputs from the permit documents (see Appendix B) available from recent IGCC projects as well as with inputs from technology suppliers and serves as a reasonable near-term target for the study.

The acid gas removal system includes a sulfur recovery process where elemental sulfur or sulfuric acid can be made. A decision on the final design configuration for the acid gas removal system for an IGCC plant will be based on whether the byproduct produced is salable and a long-term market for it exists. A sulfur recovery process is selected for this study, which is a two-step process; a Claus process followed by a Shell Claus off-gas treatment (SCOT) tail-gas cleaning. The Claus sulfur recovery unit produces elemental sulfur from the H_2S. The Claus process removes about 98% of the sulfur. The Claus tail-gas is sent to a SCOT process for further sulfur recovery. SCOT is an amine-based process and can remove 99.8% of the sulfur.

Mercury

The details for what happens to the mercury in the coal at a gasification plant are not well understood. The relatively small amounts of the element present in the gas streams are difficult to measure and make tracking the material through the gasification process very difficult. From plant experience[16, 17], it does appear that plants without carbon beds for mercury capture will release 50 to 60 percent of the coal-derived mercury in the flue gas. However, addition of relatively inexpensive carbon bed filters will remove 90 to 95% of the emitted mercury.[18] The Eastman gasification plant in Tennessee uses such controls for their chemical production and reports excellent results.[19]

The Eastman gasification plant feedstock consists of medium- to high-sulfur bituminous coals. Based on this experience, it is assumed that use of the carbon-bed technology on all three study coals would result in 90% mercury removal efficiency. While the Eastman experience validates this assumption for the bituminous coal case, the lack of experience with carbon-bed application on low-rank coals raises the potential for less than 90% mercury removal for such applications.

[16] Major Environmental Aspects of Gasification-Based Power Generation Technologies, Final Report by: Jay Ratafia-Brown, Lynn Manfredo, Jeffrey Hoffmann, & Massood Ramezan for National Energy Technology Laboratory, U.S. Department of Energy, December 2002.
[17] The Cost of Mercury Removal in an IGCC Plant Final Report Prepared for Department of Energy National Energy Technology Laboratory by Parsons Infrastructure and Technology Group Inc. September 2002.
[18] Personal contact between Nexant and ConocoPhillips, August 15, 05.
[19] Gas Turbine World, Sept – Oct 2005 Volume 35 Number 4; "IGCC Closing the $/kW Cost Gap".

The Federal New Source Performance Standards currently require a mercury limit of 20 x 10^{-6} lb/MWh for new IGCC plants.[20] Any future changes to this requirement can be seen on the referenced EPA's website.

Turbine Combustion Impacts

While some initial discussions about the environmental impacts from the syngas combustion turbines indicated them to be the same, or similar to those of natural gas-fired turbines, the technical and regulatory communities have largely recognized that the combustion characteristics of syngas and natural gas are different, and require different consideration of control technologies.

Syngas has a different calorific value, gas composition, flammability characteristics, and presence of contaminants than natural gas. The GE Energy and Shell type gasifier plants produce syngas with a heating value from 250 to 400 Btu per standard cubic foot compared to about 1,000 Btu per standard cubic foot for natural gas. The composition of natural gas is primarily methane, and the syngas components are primarily carbon monoxide and hydrogen. The H_2 causes a high flame speed and temperature. The syngas will also contain some low level of sulfur contaminants, which may impact the reliability and effectiveness of post-combustion NO_X control technologies.

A diluent, steam or nitrogen, is used to lower flame temperature and minimize NO_X creation. Nitrogen can be taken from the air separation plant and integrated with the turbine. As a byproduct of the addition of mass to the gas flow, the turbine generating capacity will increase. Section 4 discusses the use of SCR with the syngas turbine to further reduce NO_X, but for the study base IGCC cases, at this time the state-of-the-art control for syngas-fired turbines is the addition of nitrogen that reduces NO_X emission to 15 ppmvd (at 15% oxygen and ISO conditions). GE hopes to develop combustors to achieve less than 10 ppmvd NO_X with syngas.

Non-Criteria and Hazardous Air Pollutants

Depending on the coal characteristics, the non-criteria and inorganic hazardous air pollutants (HAPs) with the most environmental concerns in IGCC systems are the trace metals: arsenic, cadmium, lead, mercury, and selenium. Exhibit 1-3 shows a more complete list of EPA non-criteria pollutants and HAPS. Measurement of HAPS has proven to be difficult with existing instrumentation used for the IGCC system. Computer-based thermodynamic equilibrium studies have been reported that show these metals are volatile and will be hard to control.[21] Less volatile trace metals will likely remain with the ash or be removed by downstream gas cleaning. Mercury, which primarily remains in the vapor-phase, is a special case discussed earlier. Indications are

[20] Code of Federal Regulations, 40 CFR, Part 60, Subpart Da, http://www.epa.gov/epacfr40/chapt-I.info/chi-toc.htm, accessed 5/2/06.

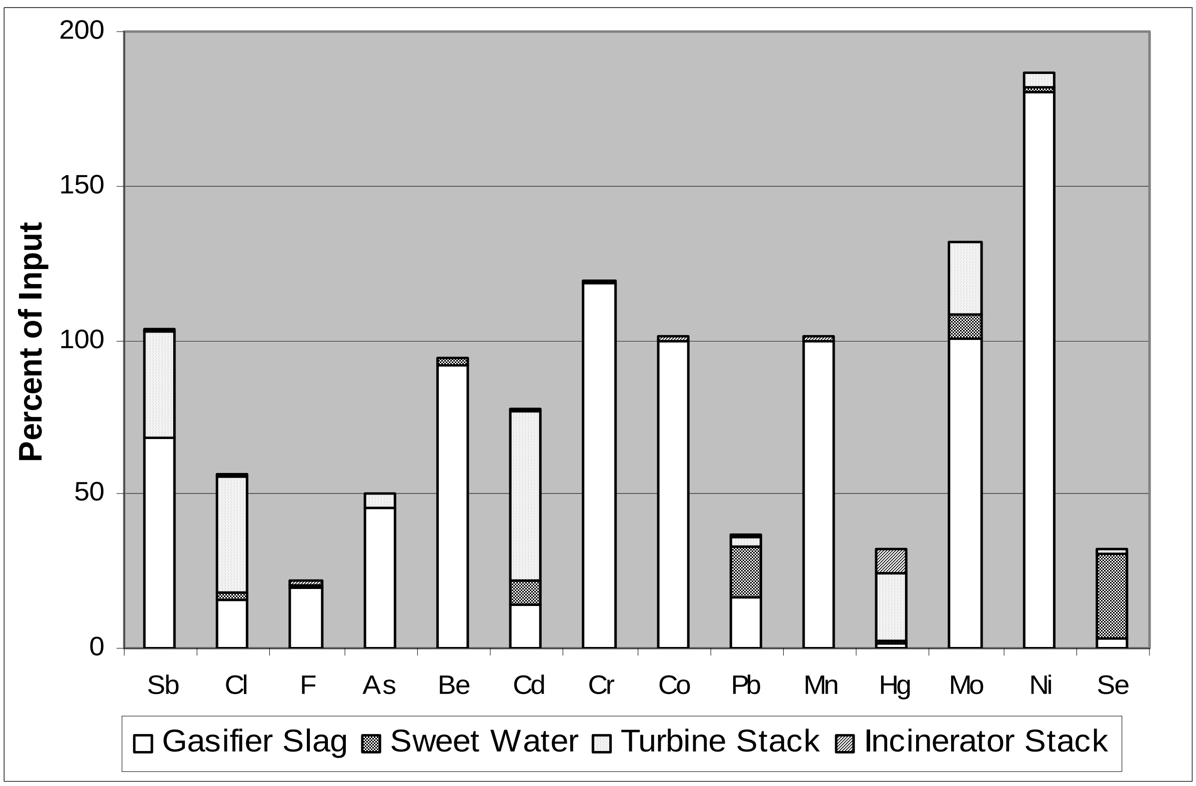
[21] Major Environmental Aspects of Gasification-Based Power Generation Technologies, Final Report by: Jay Ratafia-Brown, Lynn Manfredo, Jeffrey Hoffmann, & Massood Ramezan for National Energy Technology Laboratory, U.S. Department of Energy, December 2002.

that most of the elemental, vapor phase mercury is emitted from the gasification process. However, effective control methods with carbon filters are in commercial use for other applications, and should be available to the IGCC cases at reasonable economic costs. It is estimated that installation of carbon bed filters will reduce mercury by 90 to 95%.

The energy and material balance for HAPS and the measurement of HAP emissions is complex and difficult to forecast accurately until more operating data becomes available. Trace elements can be divided into three classifications depending on volatility and the volatility of their simple compounds, such as oxides, sulfides and chlorides. Class I elements are the least volatile and remain in the ash. Class II elements are more volatile and report to both the ash and the gaseous phases, with condensation of vaporized species on the surface of ash particles as the gas cools. Class III elements are highly volatile. Elements that exit the gasifier as vapor will further separate downstream as condensation occurs. The thermodynamic models indicate that the metals are more volatile under the reducing gasification environment than in oxidizing combustion environments.

Detailed field measurements for trace metals were conducted at the 160 MW Louisiana Gasification Technology Inc. The reported results are shown in Exhibit 3-8.[22]

Exhibit 3-8, IGCC Trace Metal Reporting within the Process



[22] Major Environmental Aspects of Gasification-Based Power Generation Technologies, Final Report by: Jay Ratafia-Brown, Lynn Manfredo, Jeffrey Hoffmann, & Massood Ramezan for National Energy Technology Laboratory, U.S. Department of Energy, December 2002.

The graph in Exhibit 3-8 shows the partitioning of the trace elements among the major outlet streams – gasifier slag, processed "sweet" water, turbine stack gas, and incinerator stack gas. The report cautions that many of the elements are present at extremely low levels and may partially accumulate within an IGCC process, it is not unusual to obtain material balance closures of less than (or more than) 100%.

Trace element emission factors (lb/10^{12} Btu input basis), calculated for total stack emissions from the Louisiana gasification plant, are presented in Exhibit 3-9, and are from the same DOE/NETL final report.

Exhibit 3-9, Estimates of IGCC Trace Element Emissions

TRACE ELEMENT	EMISSION FACTOR, lb/10^{12} Btu	
	Average	95% Confidence Level*
Antimony	4	4.7
Arsenic	2.1	1.9
Beryllium	0.09	0.03
Cadmium	2.9	3.8
Chloride	740	180
Chromium	2.7	0.63
Cobalt	0.57	0.58
Fluoride	38	22
Lead	2.9	1.5
Manganese	3.1	6.5
Mercury	1.7	0.43
Nickel	3.9	3.6
Selenium	2.9	1.3

* Mean value of the confidence interval in which there is a 95% probability that the value occurs

Trace element stack emissions are a function of their concentrations in the coal. Higher coal concentrations generally result in higher stack emissions, since the reduction levels within controls may stay the same. For the study cases, emission estimates are provided for only a few important trace elements, and these estimates either use a range of emission values or are based on coal concentrations. Exhibit 3-26 and Appendix B present a comparison of trace element limits from air permit documents for recent IGCC and PC plants.

Air Emission and Other Environmental Impact Estimates for IGCC Plants

Exhibits 3-10 and 3-11 present the environmental impact estimates for the two gasifier cases and three coals. The emission values for key air pollutants are provided in lb/MMBtu, lb/MWh, and ppmvd at 15%O_2. Lb/MWh values are based on MW gross.

Exhibit 3-10, IGCC Environmental Impacts, Slurry Feed Gasifier

GE Energy Slurry Feed Gasifier	500 MW Net Capacity Bituminous			500 MW Net Capacity Subbituminous		
Air Pollutants	Ppmvd (@ 15% O_2)	lb/MWh	lb/MMBtu	ppmvd (@ 15% O_2)	lb/MWh	lb/MMBtu
NO_X (NO_2)	15	0.355	0.049	15	0.326	0.044
SO_2	10	0.311	0.043	3	0.089	0.012
CO	15	0.217	0.030	17	0.222	0.030
Volatile Organic Compounds	--	0.012	0.0017		0.013	0.0017
Particulate Matter (overall)	--	0.051	0.007	--	0.052	0.007
Particulate Matter (PM_{10})	With the Overall Particulate Matter			With the Overall Particulate Matter		
Lead (Pb) lb/MMBtu	1.0×10^{-6} to 2.4×10^{-6} (see text below)			1.0×10^{-6} to 2.4×10^{-6} (see text below)		
Mercury		5.50×10^{-6}	0.76×10^{-6}		3.11×10^{-6}	0.42×10^{-6}
Acid Mist		0.030	0.0042		0.004	0.0005
Other Environmental Impacts	Ppmvd (@ 15% O_2)	Lb/MWh	lb/MMBtu	ppmvd (@ 15% O_2)	lb/MWh	lb/MMBtu
CO_2		1,441	199		1,541	208
Solid Waste (gasifier slag)		65	9		45	6
Raw Water Use		4,960	685		5,010	676
Sulfur Production, lb/h	8,679			1,044		
Sulfur Removal	99%			97.5%		
NO_X Removal	To 15 ppmvd			To 15 ppmvd		
Particulates	99.9% or greater. Typical value for IGCC is “negligible” emissions			99.9% or greater. Typical value for IGCC is “negligible” emissions		

Exhibit 3-11, IGCC Environmental Impacts, Solids Feed Gasifier

Shell Solid Feed Gasifier	500 MW Net Capacity Lignite		
Criteria Pollutants	ppmvd @15% O_2	lb/MWh	lb/MMBtu
NO_X (NO_2)	15	0.375	0.050
SO_2	4	0.150	0.020
CO	15	0.225	0.030
Volatile Organic Compounds		0.013	0.0017
Particulate Matter (overall)	--	0.053	0.007
Particulate Matter (PM_{10})	With the Overall Particulate Matter		
Lead (Pb), lb/MMBtu	1.0×10^{-6} to 2.4×10^{-6} (see text below)		
Mercury		5.48×10^{-6}	0.73×10^{-6}
Acid Mist		0.015	0.002
Other Environmental Impacts	ppmvd @15% O_2	lb/MWh	Lb/MMBtu
CO_2		1,584	211
Solid Waste (gasifier slag)		218	29
Raw Water Use		5,270	700
Sulfur Production, lb/h	4,370		
Sulfur Removal	99%		
NO_X Removal	To 15 ppmvd		
Particulates	99.9% or greater. Typical value for IGCC is "negligible" emissions		

The emissions for IGCC units listed above were estimated from energy and material balance calculations and other methods as noted below.

- The emission estimates have generally been based on air permit data (see Appendix B) and discussions with control technology suppliers. Only IGCC plants utilizing bituminous coal are included in the permit data available for this study. Also, only a small amount of operating data is available for IGCC application on low-rank coals.[23]

[23] H. Frey and E. Rubin, "Integration of Coal Utilization and Environmental Control in Integrated Gasification Combined Cycle Systems," Environment Science Technology, Volume 26, No. 10, 1992.

The suppliers have indicated that the performance capabilities of control technologies would remain the same for all three types of study coals. This is based on experience with gasifier applications in the petroleum and chemical industries. Therefore, the emission estimates for subbituminous coal and lignite cases have been based on reduction levels similar to those used for the bituminous coal case. Because of the lack of relevant air permit or operating data for the subbituminous coal and lignite cases, some uncertainty still remains for these two estimates.

- NO_X is controlled by dilution of the gas turbine fuel-air mixture with steam and nitrogen. Utilizing existing technology and design considerations, the achievable concentration is 15 ppmvd at 15% oxygen. This was estimated from a discussion between Nexant and GE and reviews of recent air permit data and literature.

- SO_2 is controlled by the MDEA-based acid gas cleaning system and sulfur production. This system removes 99% of the total sulfur at the IGCC plants using bituminous coal and lignite, which is based on recent air permit data and discussions with MDEA process providers. The subbituminous coal selected for this study has a relatively low sulfur content of 0.22%. The total sulfur removal rate selected for the IGCC plant using this coal is 97.5%, which is based on a sulfur concentration in the syngas of 20 ppm and that in the stack flue gas of 3 ppm[24].

- CO is controlled by good combustion practices and the limit of 0.03 lb/MMBtu is estimated from the review of recent air permit data.

- The overall Particulate Matter, including PM_{10}, is controlled by the particulate removal filters and the acid gas removal wet scrubbing of the synthesis gas. It includes filterable particulate matter only. The removal rate is nearly 100%, which is based on the review of recent air permit data.

- Fine Particulate Matter ($PM_{2.5}$) – no data was found for the fine particulate emissions.

- VOCs are controlled by good combustion practices, i.e., efficient and stable gasification. The emission limit of 0.0017 lb/MMBtu is based on the review of recent air permit data.

- Lead emissions are estimated by review of recent air permit data. This limit is expected to vary significantly with the coal, depending on the coal lead content and as more is learned about its presence in the IGCC systems. From operating experience, it appears that about 5% of the lead in the coal is emitted. The remainder is left with gasifier slag and other parts of the gas cleaning systems.

[24] Process Screening Analysis Of Alternative Gas Treating And Sulfur Removal For Gasification, Revised Final Report, December 2002, Prepared by SFA Pacific, Inc., U.S. DOE Task Order No. 739656-00100.

- Mercury limits are based on 90% removal within the controls provided specifically for mercury removal and controls for other pollutants. The uncontrolled mercury emission is based on an assumed average mercury content of each coal type, which was taken from a published source.[25] The reported emission will vary with the coal mercury content.

- Acid mist limits are based on air permit data for the bituminous coal case. For the subbituminous coal and lignite cases, the generation and removal rates used are the same as for the bituminous case.

- CO_2 is calculated with the assumption that all the carbon in the coal is converted to CO_2.

- Solid Waste is calculated using the ash content of the coals.

- Water losses are based on the USDOE/NETL report and Nexant performance spreadsheet calculations[26].

- Sulfur production is calculated based on the sulfur content of the coals.

3.3 Pulverized Coal Plant Emissions

The primary PC plant emission control devices are briefly described below. The technologies are commercially available, and are prevalent in many operating plants and in published data. The emission estimates reflected below are provided for informational purposes only. Publication of such estimates in this report does not establish the estimates as emissions limitations for any source or require that such estimates be used as emissions limitations in any permit. Emissions limitations and permit conditions should be determined by permitting authorities on a case-by-case basis considering applicable EPA and state regulations and the record in each permit proceeding.

The two most widely used flue gas desulfurization (FGD) technologies for PC plants are the wet FGD systems and dry FGD systems. In general, the wet FGD system is located downstream of the particulate control device, the flue gas is fully saturated with water, and the SO_2 reaction products are removed in a wet solid waste form. The dry FGD systems are located upstream of the particulate collection device, the flue gas is partially saturated, and the dry SO_2 reaction products are collected along with fly ash in the particulate collection device. Different types of wet and dry FGD systems are available, using different reagents. For this study, a wet limestone flue gas desulfurization (WL-FGD) system utilizing a scrubber with forced oxidation is used for the bituminous coal and lignite cases, and a lime spray dryer absorber (SDA) is used for the subbituminous

[25] Coal Analysis Results, http://www.epa.gov/ttn/atw/combust/utiltox/utoxpg.html#DA2, accessed on February 21, 2006.
[26] Power Plant Water Usage and Loss Study, U.S. DOE NETL, August 2005.

case. Most coal-fired power plants equipped with SO_2 controls use these two technologies, described below:

Flue Gas Desulfurization - Low-Sulfur Subbituminous Coal

Lime SDA is generally used to control SO_2 emissions from PC plants firing low-sulfur coal. The systems are located after the air preheaters, and the wastes are collected in a baghouse or fabric filter to achieve high rates of SO_2 removal (an electrostatic precipitator may also be used, in lieu of the fabric filter, but it requires a higher lime injection rate to achieve similar levels of SO_2 removal). The SDA treats the flue gas by injecting atomized lime slurry. The fine droplets absorb SO_2 from the flue gas and the SO_2 reacts with the lime to mostly form calcium sulfite. The cleaned flue gas, the reaction products, any unreacted lime, and the fly ash are all collected in the filters. The waste product contains $CaSO_3$, $CaSO_4$, calcium hydroxide, and ash.

SDA systems are commercial and range in size from less than 10 MW to 500 MW. Applications include commercial units with coal sulfur content as high as 2.0%. These systems are available from a number of vendors including: Alstom Environmental Systems, Babcock & Wilcox (B&W), Babcock Power, Hamon Research Cottrell, Marsulex Environmental Technologies, and Wheelabrator Air Pollution Control.

SDA systems have generally been applied to units which use low sulfur coals, including Powder River Basin and other western coals with inlet SO_2 less than 2.0 lb/MMBtu and low sulfur eastern bituminous coal with inlet SO_2 concentrations as high as 3.0 lb/MMBtu. Babcock & Wilcox installed SDA units at U.S. Operating Services' 285 MW Chamber Works Unit, which utilizes bituminous coal, in 1993 and achieved 93% removal efficiency. B&W also achieved similar efficiency at Eastman Kodak's 110 MW boiler #31, which uses bituminous coal. Alstom has achieved 95% removal efficiency at Pacific Gas and Electric Company's 330 MW Indiantown plant and South Carolina Electric and Gas Company's 385 MW Cope Unit #1, both installed in 1995.

Unlike WL-FGD absorbers, which must be constructed of expensive corrosion-resistant metals or other materials, SDA systems can be constructed of less expensive carbon steel due to the absence of water-saturated gas. Dry systems are able to efficiently capture SO_3, they efficiently remove oxidized forms of mercury from flue gas, and they consume less energy than wet systems. The SDA process has the other following advantages compared to WL-FGD technology:

- Waste products are in a dry form and can be handled with conventional pneumatic fly ash handling equipment. The waste is suitable for landfill and can be disposed of with fly ash.

- The dry system uses less equipment than does the WL-FGD system.

- Sulfur trioxide (SO_3) in the vapor form is removed efficiently with a SDA and fabric filter. Wet scrubbers capture up to 50% of SO_3 and require additional processing to avoid visible plume from the stack. New plants are likely to install wet ESP systems with the WL-FGD scrubbers to enhance SO_3 control.

- There are no liquid effluents from a dry system. Water used to slurry the lime is evaporated in the SDA process.

The dry process has the following disadvantages when compared to WL-FGD technology.

- For systems larger than about 300 MW, multiple trains of process equipment may be required.

- Lime is a more expensive reagent than the limestone used with the WL-FGD, and reagent utilization is lower for the dry system.

- The SDA waste has a few useful or commercial applications at this time. In some cases, the WL-FGD wastes can be converted to salable gypsum if there is a market.

- For the study, using coal with a sulfur content of only 0.22%, the SDA technology's SO_2 removal efficiency is 87%. If a higher sulfur coal was used, a higher removal rate would be possible.

Wet Limestone Flue Gas Desulfurization – Bituminous and Lignite Coals

WL-FGD technology is the most widely applied SO_2 removal technology for PC boilers. The forced-oxidation version of this technology produces oxidized solid waste (mostly calcium sulfate or gypsum), which is a stable compound that can be readily landfilled or sold for industrial applications, if a market exists. Another version of the WL-FGD technology produces un-oxidized solid waste (mostly calcium sulfite), which is less stable and must be mixed with other compounds, such as portland cement, to make it suitable for landfilling. The current industry trend is to use the forced oxidation system.

The main WL-FGD scrubber vessel is located after the plant's particulate removal system. The cleaned gas is then sent to the stack. The WL-FGD uses limestone or lime as a reagent. The lime is a magnesium enhanced reagent. Cost and economics will dictate the choice of reagents.

The system operation is similar for both reagents. The flue gas is treated in a limestone or lime slurry spray. Designs vary, but commonly the gas flows upward, countercurrent to the spray liquor. The slurry is atomized to fine droplets for uniform gas contact. The droplets absorb SO_2 which reacts with reagent in the slurry. Hydrogen chloride present in the flue gas is also absorbed and neutralized with reagent. Water in the spray droplets evaporates, cooling the gas to its saturated temperature (generally, 120 to 130°F). The desulfurized flue gas passes through mist eliminators to remove entrained droplets before the flue gas is sent to the stack. In some systems the clean flue gas is reheated to avoid acidic condensation in the stack. The choice of a "wet" or "dry" stack is another cost trade-off decision.

For the study, a limestone-based, forced-oxidation WL-FGD system is selected. The system SO_2 removal efficiency with bituminous coal is 98%. Due to lack of specific data, the same SO_2 mass emission rate achieved with bituminous coal is used for lignite.

NO_X Controls

The most widely applied NO_X controls for coal-fired boilers include combustion control and selective catalytic reduction (SCR) technologies. Both technologies can be applied simultaneously to maximize NO_X reduction.

Combustion controls consist of a low-NO_X burner (LNB) and the use of overfire air (OFA). These technologies utilize staged combustion techniques to reduce NO_X formation in the boiler primary combustion zone and a plant may opt to use one or both of these. An LNB limits NO_X formation by controlling the stoichiometric and temperature profiles of the combustion process. This control is achieved by design features that regulate the aerodynamic distribution and mixing of the fuel and air. OFA, also referred to as air staging, is a combustion control technology in which a fraction, 5 to 20%, of the total combustion air is diverted from the burners and injected through ports located downstream of the top burner level. OFA is used in conjunction with operating the burners at a lower-than-normal air-to-fuel ratio, which reduces NO_X formation. The OFA is then added to achieve complete combustion.

SCR is a post-combustion NO_X control technology capable of reductions in excess of 90 percent. Because NO_X reduction methods are commonly a combination of combustion controls (special burners, air and firing operations), it is difficult to specify a percent removal for SCR without a comparable case without SCR. In this report NO_X emission comparisons for the plant will be stated in units of ppmvd – parts per million by volume dry basis. Also, all the NO_X concentration estimates are adjusted to 15% oxygen so the PC and IGCC emissions can be better compared. NO_X reductions are achieved by injecting ammonia (NH_3) into the flue gas, which then goes through a catalyst. The NH_3 and NO_X react at the catalyst, forming nitrogen and water. The technology has been widely used for coal-fired applications for more than 30 years in Japan, Europe, and the United States. It has been applied to large utility and industrial boilers, process heaters, and combined cycle gas turbines. In the SCR process, NH_3 is injected into the flue gas within a temperature range of about 600 to 750 °F, upstream of the catalyst. Subsequently, as the flue gas contacts the SCR catalyst NO_X is chemically reduced when the flue gas contacts the SCR catalyst. The simple reaction is:

$$2NO + 2NH_3 + \tfrac{1}{2}O_2 \rightarrow 2N_2 + 3H_2O$$

Exhibit 2-5 illustrates the location of the SCR in a typical PC boiler system. The catalyst is located between the economizer and the air preheater; this is termed a hot-side SCR and is the most commonly used configuration. Theoretically one mole of NH_3 is required to reduce one mole of NO. It is important to keep the operation close to the theoretical limit because unreacted NH_3, or ammonia slip, will combine with SO_2 and SO_3 present in the flue gas to form ammonium sulfate and bisulfate compounds, which may cause fouling of downstream equipment.

Particulate Controls

Solid particulates are controlled by the installation of electrostatic precipitators (ESP) or fabric filters. Removal rates approach 100% with values of 99.7 to 99.9% used in the study, depending on the coal ash content and based on utilizing fabric filters. A practical system that will measure and monitor total particulates and the fine particulates, especially $PM_{2.5}$ materials, still needs to be developed by the industry.

Air Pollution Control Technology Advancements

There are ongoing activities in the industry that are concentrating on improving the performance of existing air pollution control technologies or developing new technologies. The data reported by the industry show several new technologies that are in various stages of development, with the potential to reduce costs and improve performance of controlling air pollution from coal-fired power plants.[27] Some of these technologies control more than one pollutant within the same system. These technologies were not considered for this study, as they were not considered to be commercial and available in the timeframe relevant to this study.

Non-Criteria and Hazardous Air Pollutants

HAPS from the PC plant operations are controlled by the flue gas desulfurization systems, particulate collection fabric filters and the SCR technology. The recent air permit data show the emission limits that can be achieved for certain HAPs (see Appendix B). The PC units have oxidizing combustion conditions, which help to reduce some of the HAP emissions by converting the metals to oxides that report to the ash materials. Currently, the coal ash wastes are not considered hazardous and can be disposed off in a landfill.

The potential for mercury removal with conventional controls used for criteria pollutants at PC plants was reported as shown in Exhibit 3-12.[28] The data presented in Exhibit 3-12 result in the following observations. The air pollution control technologies used on PC utility boilers exhibit average levels of mercury control that widely range in effectiveness, from 0 to 98 percent. The best levels of control are by emission control systems that use fabric filters. The amount of mercury captured by a control technology is higher for bituminous coal than for either subbituminous coal or lignite. The lower levels

[27] Multipollutant Emission Control Technology Options for Coal-Fired Power Plants, EPA-600/R-05/034, March 2005.

[28] Control Of Mercury Emissions From Coal-Fired Electric Utility Boilers(Including Update): Original Report Dated 2-2002 and Update Dated 2-18-2005, U.S. EPA Office Of Research and Development, Prepared by National Risk Management Research Laboratory Research Triangle Park, NC 27711.

Exhibit 3-12, Estimates for PC Plant Mercury Removal with Conventional Controls

Post-combustion Control Strategy	Post-combustion Emission Control Device Configuration	Average Mercury Capture by Control Configuration		
		Coal Burned in Pulverized-coal-fired Boiler		
		Bituminous	Subbituminous	Lignite
PM Control Only	CS-ESP	36 %	3%	0 %
	HS-ESP	9 %	6 %	not tested
	FF	90 %	72 %	not tested
	PS	not tested	9 %	not tested
PM Control and Spray Dryer Absorber	SDA+CS-ESP	not tested	35 %	not tested
	SDA+FF	98 %	24 %	0 %
	SDA+FF+SCR	98 %	Not tested	not tested
PM Control and Wet FGD System[(a)]	PS+FGD	12 %	0 %	33%
	CS-ESP+FGD	75 %	29 %	44 %
	HS-ESP+FGD	49 %	29 %	not tested
	FF+FGD	98 %	Not tested	not tested

Notes: (a) Estimated capture across both control devices
CS-ESP = Cold side electrostatic precipitator
HS-ESP = Hot side ESP
FF = Fabric filter
PS = Particulate scrubber
SDA = Spray dryer absorber
SCR = Selective catalytic reduction
FGD= Wet limestone flue gas desulfurization (WL-FGD)

of capture at subbituminous and lignite plants are attributed to low coal chlorine content and low fly ash carbon content and higher relative amounts of elemental mercury, instead of oxidized mercury, in the flue gas.

Plants that only use particulate controls display average mercury emission reductions ranging from 0 to 90 percent, with the highest levels of control achieved by fabric filters. Mercury control at units equipped with SDA plus ESP or fabric filters ranges from 98 percent for bituminous coals to 24 percent for subbituminous coal. The relatively low removal rates for subbituminous and lignite coals are attributed again to the small amounts of oxidized mercury in the flue gas.

Mercury removal in units equipped with wet scrubbers is dependent on the relative amount of oxidized mercury in the inlet flue gas and on the particulate control technology used. Average removal in wet scrubbers ranged from 29 percent for one PC plant with a hot-side ESP and subbituminous coal to 98 percent in a plant with a fabric filter and wet scrubber burning bituminous coal. The high removal in this unit is attributed to increased oxidization of the mercury and its capture in the fabric filter.

In general, mercury removal in PC units with SDA and WL-FGD appears to provide similar levels of control on a percentage reduction basis. However, this observation is based on a small number of short-term tests at a limited number of plants. The subbituminous coals pose a special issue: The coal's mercury exists primarily as elemental mercury, which remains a vapor in the flue gas and mostly passes through FGD and SCR controls.

Unlike the technologies described above, where mercury removal is achieved as a cobenefit with removal of other pollutants, injection of dry sorbent, specifically powdered activated carbon (PAC), has been tested for mercury control at several coal-fired utility plants in the U.S. These tests included short-term, full-scale tests, with the PAC injected into the ductwork upstream of a particulate control device, such as an ESP or fabric filter. Other short- and long-term tests are planned for the future. Results from certain major tests using optimal PAC injection rates are summarized below:[29]

- Two PC boiler plants firing low-sulfur, bituminous coals: PAC injected upstream of CS-ESPs captured approximately 94 percent mercury.

- PC boiler plant equipped with a HS-ESP and firing low-sulfur, bituminous coals: PAC injected upstream of a small fabric filter (compact hybrid particle collector or COPHAC) captured greater than 90 percent mercury.

- PC boiler plant firing high-sulfur, bituminous coals: PAC injected upstream of a CS-ESP captured 73 percent mercury.

- PC boiler plant firing a subbituminous coals: PAC injected upstream of a CS-ESP captured 65 percent mercury.

The above data show that mercury removal was higher with PAC injection for low-sulfur bituminous coals than for subbituminous or high-sulfur bituminous coals. It is believed that higher amounts of chlorine present in bituminous coals promote oxidation of elemental mercury, thus facilitating its removal by PAC. Also, higher SO_3 content of high-sulfur coal flue gas may interfere with the capture of mercury by PAC.

In addition to the above tests with conventional PAC, other short-term tests have also been conducted using enhanced or halogenated PAC. The results from these tests show more encouraging results, especially for low-rank coals, as explained below.[29]

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[29] Control Of Mercury Emissions From Coal-Fired Electric Utility Boilers(Including Update): Original Report Dated 2-2002 and Update Dated 2-18-2005, U.S. EPA Office Of Research and Development, Prepared by National Risk Management Research Laboratory Research Triangle Park, NC 27711.

- PC boiler plants firing subbituminous or blended subbituminous coals: halogenated PAC injected upstream of CS-ESPs captured 80 to 94 percent mercury.

- PC boiler plant equipped with SDA and firing subbituminous coals: halogenated PAC injected upstream of a fabric filter captured 93 percent mercury.

- PC boiler plant firing high-sulfur bituminous coals: halogenated PAC injected upstream of a CS-ESP captured 70 percent mercury.

- PC boiler plant firing low-sulfur bituminous coals: halogenated PAC injected upstream of a HS-ESP captured greater than 80 percent mercury.

- PC boiler plant equipped with SDA and firing lignite: halogenated PAC injected upstream of a fabric filter captured 95 percent mercury.

Based on the above data, the following controls and mercury reduction levels were assumed for this study (since the data are based on short-term test results, uncertainties exist with the assumed reduction levels, and it is recognized that these levels may not be attainable for all new PC plants in the time frame selected for the study):

- With bituminous coal cases, where WL-FGD, SCR, fabric filter, and wet ESP are used, mercury removal is 90%.

- For subbituminous and lignite coals, the conventional controls reduce mercury by 70%. Activated carbon injection is added to achieve an overall 90% reduction.

The Federal NSPS require the following mercury emission limits for new PC plants (see EPA website for specific requirements or any future changes to these requirements):[30]

- For PC plants firing bituminous coals: 20×10^{-6} lb/MWh
- For PC plants firing sub-bituminous coals in county-level geographical areas with greater than 25 inches/year mean annual rain: 66×10^{-6} lb/MWh
- For PC plants firing sub-bituminous coals in county-level geographical areas with less than or equal to 25 inches/year mean annual rain: 97×10^{-6} lb/MWh
- For PC plants firing lignite: 175×10^{-6} lb/MWh

Air Emission and Other Effluent Estimates for PC Plants

Exhibits 3-13, 3-14, and 3-15 list the environmental impact estimates for PC plants and the three coals. The emission values for key air pollutants are provided in lb/MMBtu, lb/MWh, and ppmvd at 15%O_2. Lb/MWh values are based on MW gross. Following the exhibits, there is a brief discussion of how the emission values were obtained.

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[30] Code of Federal Regulations, 40 CFR, Part 60, Subpart Da, http://www.epa.gov/epacfr40/chapt-I.info/chi-toc.htm, accessed 7/6/06.

Exhibit 3-13, Subcritical Pulverized Coal Plant Environmental Impacts

Subcritical PC	Bituminous			Subbituminous			Lignite		
Air Pollutants	ppmvd @15% O_2	lb/MWh	lb/MMBtu	ppmvd @15% O_2	lb/MWh	lb/MMBtu	Ppmvd @15% O_2	lb/MWh	lb/MMBtu
NO_X (NO_2) [1]	14	0.528	0.06	15	0.543	0.06	20	0.568	0.06
SO_2 [1]	15	0.757	0.086	11	0.589	0.065	10	0.814	0.086
CO [2]	39	0.880	0.10	40	0.906	0.10	55	0.947	0.10
Volatile Organic Compounds[2]		0.021	0.0024		0.025	0.0027		0.026	0.0027
Particulate Matter (overall) [1]		0.106	0.012		0.109	0.012		0.114	0.012
Particulate Matter (PM_{10}) [1]		0.106	0.012		0.109	0.012		0.114	0.012
Lead (Pb) [2]		$3.40x10^{-5}$ to $18x10^{-5}$	$3.86.x10^{-6}$ to $20x10^{-6}$		$18.1x10^{-5}$ to $23x0^{-5}$	$20x10^{-6}$ to $25.6x10^{-6}$		$18.9x10^{-5}$ to $24x10^{-5}$	$20x10^{-6}$ to $25.6x10^{-6}$
Mercury		$6.69x10^{-6}$	$0.76x10^{-6}$		$3.80x10^{-6}$	$0.42x10^{-6}$		$6.9x10^{-6}$	$0.73x10^{-6}$
Acid Mist		0.088	0.010		0.018	0.002		0.038	0.004
Other Environmental Impacts		lb/MWh	lb/MMBtu		lb/MWh	lb/MMBtu		lb/MWh	lb/MMBtu
CO_2[1]		1,777	202		1,893	209		1,998	211
Solid Waste (ash/FGD waste)		176	20		73	8		331	35
Raw Water Use		9,260	1,050		9,520	1,050		9,960	1,050
Sulfur Removal, %		98			87			95.8	
Particulates, Removal, %		99.8			99.7			99.9	

1. Calculated based on air permit data, discussions with equipment suppliers, literature, and process model software.
2. Estimated from review of air permit data.

Exhibit 3-14, Supercritical Pulverized Coal Plant Environmental Impacts

Supercritical PC	Bituminous			Subbituminous			Lignite		
Criteria Pollutants	ppmvd @15% O_2	lb/MWh	lb/MMBtu	ppmvd @15% O_2	lb/MWh	lb/MMBtu	ppmvd @15% O_2	lb/MWh	lb/MMBtu
NO_X (NO_2) [1]	14	0.494	0.06	15	0.500	0.06	14	0.524	0.06
SO_2 [1]	15	0.709	0.086	11	0.541	0.065	7	0.751	0.086
CO [2]	39	0.824	0.10	40	0.832	0.10	39	0.873	0.10
Volatile Organic Compounds[2]		0.020	0.0024		0.023	0.0027		0.024	0.0027
Particulate Matter (overall) [1]		0.099	0.012		0.100	0.012		0.105	0.012
Particulate Matter (PM_{10}) [1]		0.099	0.012		0.100	0.012		0.105	0.012
Lead (Pb) [2]		$3.18x10^{-5}$ to $17x10^{-5}$	$3.86.x10^{-6}$ to $20x10^{-6}$		$16.6x10^{-5}$ to $21x10^{-5}$	$20x10^{-6}$ to $25.6x10^{-6}$		$17.5x10^{-5}$ to $22x10^{-5}$	$20x10^{-6}$ to $25.6x10^{-6}$
Mercury		$6.26x10^{-6}$	$0.76x10^{-6}$		$3.49x10^{-6}$	$0.42x10^{-6}$		$6.37x10^{-6}$	$0.73x10^{-6}$
Acid Mist		0.082	0.010		0.017	0.002		0.035	0.004
Other Environmental Impacts		lb/MWh	lb/MMBtu		lb/MWh	lb/MMBtu		lb/MWh	lb/MMBtu
CO_2[1]		1,665	202		1,739	209		1,842	211
Solid Waste (ash/FGD wastes)		165	20		67	8		306	35
Raw Water Use		8,640	1,050		8,830	1,060		9,200	1,055
Sulfur Removal, %		98			87			95.8	
Particulates Removal, %		99.8			99.7			99.9	

1. Calculated based on air permit data, discussions with equipment suppliers, literature, and process model software.
2. Estimated from review of air permit data.

Exhibit 3-15, Ultra Supercritical Pulverized Coal Plant Environmental Impacts

Ultra Supercritical PC	Bituminous			Subbituminous			Lignite		
Criteria Pollutants	ppmvd @15% O_2	lb/MWh	lb/MMBtu	ppmvd @15% O_2	lb/MWh	lb/MMBtu	ppmvd @15% O_2	lb/MWh	lb/MMBtu
NO_X (NO_2) [1]	14	0.442	0.06	15	0.450	0.06	14	0.498	0.06
SO_2 [1]	15	0.634	0.086	11	0.488	0.065	7	0.714	0.086
CO [2]	39	0.737	0.10	40	0.750	0.10	39	0.830	0.10
Volatile Organic Compounds[2]		0.018	0.0024		0.020	0.0027		0.022	0.0027
Particulate Matter (overall) [1]		0.088	0.012		0.090	0.012		0.100	0.012
Particulate Matter (PM_{10}) [1]		0.088	0.012		0.090	0.012		0.100	0.012
Lead (Pb) [2]		2.84×10^{-5} to 15×10^{-5}	$3.86. \times 10^{-6}$ to 20×10^{-6}		15.0×10^{-5} to 19×10^{-5}	20×10^{-6} to 25.6×10^{-6}		16.6×10^{-5} to 21×10^{-5}	20×10^{-6} to 25.6×10^{-6}
Mercury		5.60×10^{-6}	0.76×10^{-6}		3.15×10^{-6}	0.42×10^{-6}		6.06×10^{-6}	0.73×10^{-6}
Acid Mist		0.074	0.010		0.015	0.002		0.033	0.004
Other Environmental Impacts		lb/MWh	lb/MMBtu		lb/MWh	lb/MMBtu		lb/MWh	lb/MMBtu
CO_2[1]		1,488	202		1,568	209		1752	211
Solid Waste (ash/FGD wastes)		155	21		60	8		291	35
Raw Water Use		7,730	1,050		7,870	1,050		8,710	1,050
Sulfur Removal, %		98			87			95.8	
Particulates removal, %		99.8			99.7			99.9	

1. Calculated based on air permits, discussions with equipment suppliers, literature, and process model software.
2. Estimated from review of air permit data.

The emissions from the PC units listed above were estimated from energy and material balance calculations and other methods as noted below.

- The emission limits for various pollutants have generally been based on air permit data (see Appendix B) and discussions with control technology suppliers.
- NO_X is reduced through use of combustion controls and SCR. The emission rate is estimated at 0.06 lb per MMBtu for all the plants. These estimates use air permit data, data from contacts with SCR suppliers, and data available from literature[31].
- SO_2 is controlled by a WL-FGD for the bituminous coal and lignite. The estimated removal rates are 98 and 95.8% for bituminous coal and lignite, respectively. The subbituminous coal plants use lime SDA technology and the removal efficiency is 87%. The SO_2 removal rates selected for both technologies are from air permit data, vendor contacts, and the literature[32, 33]. The SDA system treats flue gases originating from a coal with a sulfur content of only 0.22%. Based on the air permit data (see Appendix B), a controlled SO_2 emission rate of 0.065 lb/MMBtu was selected for this system, which results in the relatively low removal efficiency of 87%. With higher coal sulfur content, higher removal efficiencies can be expected from the SDA system of the type used in this study. Due to lack of recent data, the SO_2 mass emission rate with lignite firing is assumed to be the same as for bituminous coal.
- CO emissions are controlled by good combustion practices and estimated by reviews of the air permit data.
- The overall particulate matter and PM_{10} removal rates approach 100% and removal rates of 99.7 to 99.9% are used in this study, depending on the coal ash content and based on utilizing fabric filters. These removal rates are from air permit data and discussions with filter providers. The emissions rates include filterable particulate matter only.
- Fine Particulate Matter ($PM_{2.5}$) - no data was found for the fine particulate emissions.
- VOCs are controlled by good combustion practices, i.e. efficient and stable combustion. The limits listed in the exhibit are from recent air permit data.
- Lead is estimated by review of recent air permit data. It is expected to vary significantly based on site and fuel specifics, especially the coal lead content.

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[31] M. Oliva, et al., "Performance Analysis Of SCR Installations On Coal-Fired Boilers," Pittsburgh Coal Conference, September 2005, Pittsburgh, PA.
[32] Wet Flue Gas Desulfurization Technology Evaluation, Project Number 11311-000 Prepared for National Lime Association by Sargent & Lundy, January 2003.
[33] Dry Flue Gas Desulfurization Technology Evaluation, Project Number 11311-000 Prepared for National Lime Association by Sargent & Lundy, September 2002.

- Mercury limits are based on 90% removal within the controls provided specifically for mercury removal and controls for other pollutants. The uncontrolled mercury emissions are based on an assumed average mercury content of each coal type, which was taken from a published source.[34] The reported emissions will vary with the coal mercury contents.

- Acid mist limits are based on 95% removal within the combined WL-FGD and wet ESP systems and 90% removal in the lime SDA system.

- CO_2 emissions are calculated, and it is assumed that all the carbon in the coal is converted to CO_2.

- Solid waste is calculated using the ash content of the coals and the FGD gypsum or lime wastes.

- Water losses are calculated based on the USDOE/NETL report and Nexant's performance software.[35]

3.4 Air Permit Data

Air permit data for the following facilities were examined. Information about a diversity of technologies and coals was sought.

1. Elm Road, Wisconsin: Two 615 MW Supercritical Pulverized Coal (PC) Units
2. Comanche Generating Station Unit 3, Colorado: One 7,421 MMBtu/hr Supercritical PC Unit
3. Longview Power, LLC, West Virginia: One 600 MW Subcritical PC Unit
4. Prairie State Generating Station, Illinois: Two 750 MW Subcritical PC Units
5. Intermountain Power Generating Station Unit 3, Utah: One 900 MW Subcritical PC Unit
6. Indeck-Elwood Energy Center, Illinois: Two 330 MW Circulating Fluidized Bed (CFB) Boiler Units
7. Plum Point Energy Station, Arkansas: One 550-800 MW PC Unit
8. Thoroughbred Generating Station, Kentucky: Two 750 MW PC Units
9. TS Power Plant, Nevada: One 200 MW PC Unit
10. Santee Cooper Cross Generating Station Units 3 and 4, South Carolina: Two 5,700 MMBtu/hr PC Units
11. Holocomb Unit 2, Kansas: One 660 MW PC Unit
12. Limestone Electric Generating Station Units 1 and 2, Texas: Two 7,863 MMBtu/hr PC Units

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[34] Coal Analysis Results, http://www.epa.gov/ttn/atw/combust/utiltox/utoxpg.html#DA2, accessed on February 21, 2006.
[35] Power Plant Water Usage and Loss Study, U.S. DOE NETL, August 2005.

13. Elm Road, Wisconsin: One 600 MW IGCC Unit
14. Kentucky Pioneer Energy Facility, Kentucky: One 540 MW IGCC Unit
15. Polk Power Station, Florida: One 260 MW IGCC Unit
16. Southern Illinois Clean Energy Center, Illinois: One 544 MW IGCC Unit
17. Cash Creek, Kentucky: One 677 MW IGCC Unit

Appendix B provides a detailed list of data from the permit documents for the above-listed facilities on air emission limits for the criteria and non-criteria pollutants. It also lists these permit documents. The following sections summarize these data.

3.4.1 Criteria Pollutants

Exhibit 3-16 summarizes the data from the permit documents on criteria pollutants. The data point column shows the number of plants for that type of plant and fuel which were reviewed. Data points in the third and last rows document how many of the pollutants were regulated in the permits. For example, all five PC unit permits had data for NO_X, SO_2, CO and overall particulates; only four permits provided PM_{10} data, and none specified $PM_{2.5}$ limits.

Exhibit 3-16, Air Permit Data and Estimates for Criteria Pollutants
Pounds per Million Btu (except lead)

Data Points	Fuel (some plants may use more than one, or blend)	Nitrogen Oxides (NO_X)	Sulfur Dioxide (SO_2)	Carbon Monoxide (CO)	Particulate Matter (overall)	Particulate Matter (PM_{10})	Fine Particulate Matter ($PM_{2.5}$)	Lead (Pb) lb/10^{12} Btu
6	PC Units Bituminous Coal	0.07 to 0.08	0.1 to 0.182 (95 to 98% reduction)	0.1 to 0.16	0.012 to 0.018	0.018	No Data	3.86 to 20
5	PC Units Subbituminous Coal	0.067 to 0.09	0.065 to 0.12 (one unit with 94% reduction)	0.13 to 0.16	0.012 to 0.020	0.012 to 0.020	No Data	20 to 25.6
1	PC Units Lignite	0.5	0.82	0.11	0.03	No Data	No Data	33
12	Data Points All Pulverized Coal Units	12	12	12	10	9	0	9
1	High Sulfur Bituminous Coal CFB Unit	0.10	0.15	0.10	0.015	No Data	No Data	No Data

Exhibit 3-16, Air Permit Data and Estimates for Criteria Pollutants
Pounds per Million Btu (except lead), Cont'd

Data Points	Fuel (some plants may use more than one, or blend)	Nitrogen Oxides (NO_X)	Sulfur Dioxide (SO_2)	Carbon Monoxide (CO)	Particulate Matter (overall)	Particulate Matter (PM_{10})	Fine Particulate Matter ($PM_{2.5}$)	Lead (Pb) lb/10^{12} Btu
5	IGCC Units Bituminous Coal	0.055 to 0.10 (15 to 25 ppmvd@ 15% O_2)	0.03 to 0.17 (97 to 99.36% reduction)	0.03 to 0.046	0.007 to 0.011	0.007 to 0.011	No Data	1.0 to 25.7
5	Data Points IGCC Units	5	5	5	5	5	0	4

3.4.2 Non-Criteria Pollutants

Much less data was found in the literature to help estimate the environmental impacts of non-criteria pollutants. Data from recent power plant air permits were selected as a primary source of data. While permit limits can vary across States and may depend upon site- and fuel-specific considerations, relatively consistent values were found in the air permit data. The results are summarized in Exhibit 3-26 at the end of Section 3.

3.5 Emission and Air Pollution Control Data from the Literature

A reference list is included at the end of the report. Several of the most recent and useful documents are discussed here. Exhibit 3-17 is a helpful summary from a December 2002 U.S. DOE/NETL report. While the technologies are still developing and changing, the information is a good summation of IGCC and PC plant environmental impacts.

Exhibit 3-17 Summary of IGCC and PC Environmental Controls[36]

	Integrated Gasification Combined Cycle	Pulverized Coal Power Plant
Sulfur Control and Sulfur Byproducts	Greater than 98% sulfur control. H_2S and COS are removed from the syngas in an amine-based scrubber prior to combustion and recovered as elemental sulfur or sulfuric acid. Both are salable industrial commodities.	Up to 98% sulfur control. SO_2 is usually removed in a flue gas desulfurization process, such as a wet limestone scrubber. Advanced limestone FGD scrubbers typically produce a gypsum byproduct. Gypsum can be safely landfilled or sold for production of wallboard or utilized for other purposes.

[36] Major Environmental Aspects of Gasification-Based Power Generation Technologies, Final Report by: Jay Ratafia-Brown, Lynn Manfredo, Jeffrey Hoffmann, & Massood Ramezan for National Energy Technology Laboratory, U.S. Department of Energy, December 2002.

Exhibit 3-17 Summary of IGCC and PC Environmental Controls, Cont'd

Nitrogen Oxides Control	Fuel nitrogen mainly converted to N_2 and small amount of NH_3 and HCN, with the latter removed via syngas cleaning. Diluents, such as nitrogen and steam, are used in the gas turbine to lower the combustion flame temperature to minimize NO_X generation. Use of add-on control technologies, such as SCR, at this time has not been demonstrated for coal-based syngas-fired turbines.	Fuel nitrogen converted to NO_X. Low-NO_X burners are used to minimize conversion to NO_X. The NO_X formed may be removed with additional control technology, such as SCR. SCR unit can be installed between economizer and air heater. NH_3 preferentially adsorbs onto fly ash. Sulfates and bisulfates captured in particulate control equipment downstream of SCR.
Particulate Control	Virtually all particulate is removed. Fly ash entrained with syngas is removed downstream in wet scrubber. No acid mist problem.	Very high levels of particulate control. Fly ash is efficiently collected in a control device, such as an ESP or fabric filter. Acid mist may be a problem from FGD unit. A wet ESP can be installed downstream of the FGD to remove acid mist.
Trace Substance Control (metals and organics)	Most semi-volatile and volatile trace metals condensed and removed in syngas cleaning equipment. Elemental mercury emissions may exit with flue gas. Other metals exit with wastewater blowdown and wastewater treatment material. Trace organic emissions are extremely low. Activated carbon beds have been commercially demonstrated to remove more than 90% of syngas mercury.	Most semi-volatile and volatile trace metals condense on fly ash particles and are effectively removed with fly ash. Elemental mercury emissions may exit with flue gas. Other elements exit with ash and FGD byproduct. Trace organic emissions are extremely low. Hg emissions may depend on coal type and presence of FGD. system. Activated carbon injection upstream of a fabric filter can be added to remove 90% of mercury.
Solid Waste Disposal/ Utilization	Slag material is environmentally benign and can be safely landfilled. Slag can also be safely utilized for various applications, such as drainage material or roofing granules. Similar to material produced by wet-bottom PC plants.	Bottom ash and fly ash can be safely landfilled. Leaching of trace metals adsorbed by fly ash is more likely than with slag material. Ash can be utilized for a variety of applications, such as cement/concrete production and waste stabilization or solidification.
Carbon Dioxide Control Potential	Higher thermodynamic efficiency of IGCC cycle minimizes CO_2 emissions relative to other technologies. High pressure and high CO_2 concentration in synfuel provides optimum conditions for CO_2 removal prior to combustion, if required.	Generally higher CO_2 emissions than IGCC due to lower cycle efficiency. CO_2 removal from flue gas more technically challenging and more expensive than IGCC, based on existing technology.

Exhibit 3-18 compares IGCC and PC plant emission projections from various literature sources.

Exhibit 3-18, Emission Data from the Literature

Pollutant	IGCC Plant[37]	PC Plant[38]	EPRI Report PC and IGCC Plants[39]	Generic IGCC Plant[40]
SO_2	0.08 lb/MMBtu 0.7 lb/MWh	0.3 lb/MMBtu	99.5% removal	0.08 lb/MMBtu
NO_X (as NO_2))	0.09 lb/MMBtu 0.8 lb/MWh	0.09 lb/MMBtu	15 to 20 ppmvd	0.06 lb/MMBtu
PM_{10}, Particulate and Sulfuric Acid Mist	<0.015 lb/MMBtu <0.14 lb/MWh	0.03 lb/MMBtu	0.004 lb/MMBtu or less	0.006 lb/MMBtu
CO_2		2.0 lb/kWh		1.76 – 1.6 lb/kWh
Hg		80 – 90% removal		90 – 95% removal

3.6 PC Solid Wastes and Liquid Effluents

Estimates of solid wastes are summarized in Exhibit 3-19 for the PC plants and coals. Estimated values are shown in terms of pounds per hour and per million Btu of coal input. Estimates for the coal-ash wastes are relatively clear and leave little uncertainty; except for adjustments for unburned carbon and the small amounts of ash that are not captured, coal ash wastes are approximately “coal ash in = coal ash out”.

[37] R. Brown, et al., “An Environmental Assessment of IGCC Power Systems,” 19th Annual Pittsburgh Coal Conference, September 2002.
[38] D. Radcliffe, “IGCC- An Important Part of Our Future Generation Mix,” Workshop on Gasification Technologies, Knoxville, TN, April 12, 2005.
[39] Pulverized Coal And IGCC Plant Cost And Performance Estimates, George Booras & Neville Holt EPRI, Gasification Technologies 2004, Washington, DC, October 3-6, 2004.
[40] Major Environmental Aspects of Gasification-Based Power Generation Technologies, Final Report by: Jay Ratafia-Brown, Lynn Manfredo, Jeffrey Hoffmann, & Massood Ramezan for National Energy Technology Laboratory, U.S. Department of Energy, December 2002.

Exhibit 3-19, PC Plant Solid Waste Estimate

PC Technology 500 MW Net	Subcritical Boiler			Supercritical Boiler			Ultra Supercritical Boiler		
Study Coal	High Sulfur Bituminous	Low Sulfur Sub-Bituminous	Lignite	High Sulfur Bituminous	Low Sulfur Sub-Bituminous	Lignite	High Sulfur Bituminous	Low Sulfur Sub-Bituminous	Lignite
Sulfur Control	WL-FGD	SDA+ Filter	WL-FGD	WL-FGD	SDA+ Filter	WL-FGD	WL-FGD	SDA+ Filter	WL-FGD
UNITS	lbs/hr dry	lbs/hr dry	lbs/hr dry	lbs/hr dry	lbs/hr dry	lbs/hr dry	lbs/hr dry	lbs/hr dry	lbs/hr dry
Total Coal Ash	40,674	25,168	146,537	38,104	23,370	135,155	34,252	20,802	129,465
Bottom Ash	8,427	5,421	29,738	7,894	5,034	27,428	7,096	4,481	26,273
Fly Ash (with unburned carbon)	33,707	With SDA Filter Waste	118,461	31,132	With SDA Filter Waste	109,260	27,985	With SDA Filter Waste	104,660
Desulfurization Products -dry basis	54,086	34,656	30,741	51,802	32,181	29,432	49,395	28,644	28,066
Total Solid Waste	96,220	40,077	178,940	90,828	37,215	166,120	84,476	33,125	158,999
UNITS	lb/MMBtu	lb/MMBtu	lb/MMBtu	lb/MMBtu	Lb/MMBtu	lb/MMBtu	lb/MMBtu	lb/MMBtu	lb/MMBtu
Total Coal Ash	8.6	5.1	28.5	8.6	5.1	28.5	8.6	5.1	28.5
Bottom Ash	1.8	1.1	5.8	1.8	1.1	5.8	1.8	1.1	5.8
Fly Ash (with unburned carbon)	7.1	With SDA Filter Waste	23.0	7.0	With SDA Filter Waste	23.0	7.0	With SDA Filter Waste	23.0
Desulfurization Products -dry basis	11.4	7.1	6.0	11.6	7.1	6.2	12.3	7.1	6.2
Total Solid Waste	20.3	8.2	34.7	20.4	8.2	35.0	21.1	8.2	34.9

Waste estimates from the two sulfur removal processes are more uncertain and dependent on the amounts of limestone or lime used to capture the sulfur, and other engineering factors. The estimates here are calculated by Nexant's PC plant process model.

The solid wastes generated from PC plants have several industrial uses, including gypsum wallboard, cement additive, concrete admixture, flowable fill material, autoclaved aerated concrete blocks, waste stabilization, roadway/runway construction, mine reclamation, and agriculture applications. The salability of each of the four different types of PC solid wastes, including fly ash, bottom ash, gypsum from the wet FGD system, and waste from the dry FGD system, generally depends on whether a market exists for its use near the plant. If any of these wastes cannot be sold, they would typically be disposed off in an on-site or off-site landfill.

Experience from existing coal-fired plant operations in the U.S. shows that some of these plants are able to sell their solid waste products for industrial use, especially fly ash and FGD gypsum[41]. The reported data show that while 20 percent of these plants sold fly ash, only 16 percent were able to sell bottom ash. Similarly, 26 percent of the 268 units equipped with wet FGD systems sold their gypsum, while only 5 percent of the 234 units equipped with dry FGD systems were able sell their FGD wastes. For the purpose of this study, no credit has been taken for the sale of any solid wastes, since the data show the majority of the plants disposing of their wastes in landfills.

There are several on-going programs in the industry to encourage use of coal combustion and FGD products. As an example, government organizations, such as EPA and DOE, have formed partnerships with other government and industry stakeholders to increase the amount of coal byproduct utilization.[42] A future increase in the use of solid wastes generated from the PC plants can be expected. Such an increase would result in a reduction of the solid waste volumes required to be landfilled.

A report from DOE examines in relative detail the water usage and losses at PC and IGCC plants.[43] The DOE report is used here as the basis for water balance assessments. It is noted however that water balances vary significantly because of raw water quality and design criteria, such as the number of cycles for the cooling tower water to be circulated. The number of cooling water cycles may vary from 2 to 6 cycles, which by itself can strongly impact the amounts of makeup water required. The DOE report assumes 3 cycles for PC and IGCC cooling water systems and thus provides a consistent source of data for comparison.

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[41] EIA website, EIA-767 Data Files for 2004, http://www.eia.doe.gov/cneaf/electricity/page/eia767.html, accessed January 27, 2006.
[42] U.S. EPA Coal Combustion Products Partnership, www.epa.gov/epaoswer/osw/conserve/c2p2/index.htm, accessed February 14, 2006.
[43] Power Plant Water Usage and Loss Study, U.S. DOE NETL, August 2005.

The DOE water study is for nominal 500 MW PC and IGCC plants. This study examines GE Energy, ConocoPhillips and Shell gasification, and subcritical and supercritical PC plants. A high sulfur bituminous coal (Pittsburgh #8 seam) is used for all the plants. The study does not examine an ultra-supercritical technology plant.

For reference, the subcritical and supercritical plant water balance estimates are presented (with rounding) from the DOE study in Exhibit 3-20.

Exhibit 3-20, Summary of PC Plant Water Balances
U.S. DOE/NETL Study Results

	Subcritical PC	Supercritical PC
Plant Gross Output, MW	554	550
Plant Net Heat Rate (HHV), Btu/kWh	9,638	8,564
Water Source	Flowrate, Gallon per Minute	
Coal Moisture	48	43
Conversion of Coal Hydrogen	326	288
Combustion Air Moisture	63	57
Air to WLFGD	0.4	0.3
Raw Water Use	10,146	8,990
TOTAL	10,584	9,378
Water Loss		
Flue Gas Exhaust	928	818
Water with FGD Gypsum	81	71
Cooling Tower Evaporation	6,415	5,688
Cooling Tower Blowdown	3,160	2,801
TOTAL	10,584	9,378

The water balance estimates for the present study PC plants and coals are shown in Exhibit 3-21. In these estimate, the cooling tower losses from evaporation and blowdown are by far the largest. Evaporative losses basically correspond to the size of the steam generation system, and blowdown is required periodically to limit the buildup of solids and other contaminants in the water system. Blowdowns from all the other parts of the plant, being relatively uncontaminated, are used as part of the cooling water makeup. Notes on the estimating procedures used with Exhibit 3-21 are listed below.

- Coal Moisture is calculated from the properties of each study coal.

- Conversions of Coal Hydrogen, Combustion Air Moisture, and Air to WL-FGD are calculated using the heat rate and gross output adjustment factors of the U.S. DOE study and the present study to estimate water flowrates.

Exhibit 3-21, Estimated Water Balances for PC Plants and Coals
Gallon per Minute

PC Technology 500 MW Net	Subcritical Boiler			Supercritical Boiler			Ultra Supercritical Boiler		
Study Coal	High Sulfur Bituminous	Low Sulfur Sub-Bituminous	Lignite	High Sulfur Bituminous	Low Sulfur Sub-Bituminous	Lignite	High Sulfur Bituminous	Low Sulfur Sub-Bituminous	Lignite
Plant Gross Output, MW	540	541	544	540	541	544	543	543	546
Plant Net Heat Rate (HHV), Btu/kWh	9,500	9,800	10,300	8,900	9,000	9,500	8,000	8,146	9,065
Water Source									
Coal Moisture	94	318	531	88	295	490	79	263	469
Conversion of Coal Hydrogen	313	324	342	294	298	316	266	271	303
Combustion Air Moisture	61	63	66	58	59	63	53	54	60
Air to WLFGD	0.4	-	0.4	0.3	-	0.3	0.3	-	0.3
Raw Water Use	9,701	9,772	10,168	9,129	9,015	9,421	8,251	8,196	9,023
TOTAL	10,169	10,477	11,107	9,569	9,667	10,290	8,649	8,784	9,855
Water Loss									
Flue Gas Exhaust	892	922	974	835	846	898	754	768	860
Water with FGD Gypsum	78	-	85	72	-	78	66	-	75
Spray Dry Absorption Evaporation		48			46			44	
Cooling Tower Evaporation	6,163	6,369	6,732	5,804	5,880	6,241	5,246	5,342	5,977
Cooling Tower Blowdown	3,036	3,138	3,316	2,858	2,895	3,073	2,583	2,630	2,943
TOTAL	10,169	10,477	11,107	9,569	9,667	10,290	8,649	8,784	9,855

- Flue Gas Exhaust, Water with FGD Gypsum, Cooling Tower Evaporation, and Cooling Tower Blowdown are similarly calculated by the heat rate and gross output relationships.

- Spray Dry Absorption Evaporation is estimated from the process material balance sheets for the subbituminous coal cases.

- Raw Water is calculated as the difference between the total of water sources and the total of water losses in the items above.

The final PC plant blowdown/waste stream is typically sent to a pond or other evaporation system or is discharged to an outside source, after proper treatment. After evaporation, the remaining solid materials are secured in place or may be disposed off in other ways. Some of the water may be used for dust control or other plant operations, depending on the water quality.

3.7 IGCC Solid Wastes and Liquid Effluents

Exhibit 3-22 shows estimates of the IGCC plant solid wastes. The wastes are estimated by calculations in Nexant's gasification model. The gasifier slag consists of the coal ash, unburned carbon or char left with the ash. The sulfur product may or may not be a waste depending on the plant's ability to market and sell the sulfur. The gasifier slag can also be sold for industrial use, such as to cement industry. However, it is shown as a waste product in Exhibit 3-22.

Exhibit 3-22, IGCC and Supercritical PC Solid Wastes

Gasification Technology	Slurry Fed Gasifier	Slurry Fed Gasifier	Dry Fed Gasifier	Supercritical PC Total Solid Waste		
Study Coal	High Sulfur Bituminous	Low Sulfur Sub-Bituminous	Lignite	High Sulfur Bituminous	Low Sulfur Sub-Bituminous	Lignite
Unit Rating MW Net	500	500	500			
Gross Generation MW	564	575	580			
Net Efficiency %	41.8	40	39.2			
UNITS	lbs/hr, dry	lbs/hr, dry	lbs/hr, dry	lbs/hr, dry	lbs/hr, dry	lbs/hr, dry
Gasifier Slag	36,054	25,185	124,099	96,220	40,077	178,940
Sulfur Product	8,679	1,044	4,370			
UNITS	lb/MMBtu	lb/MMBtu	lb/MMBtu	lb/MMBtu	lb/MMBtu	lb/MMBtu
Gasifier Slag	8.8	5.9	28.5	20.3	8.2	34.7
Sulfur Product	2.1	0.2	1.0			

The three columns on the right show the supercritical PC plant total waste estimates. In comparison with the supercritical PC plants, the gasifier slag is approximately 40%, 60% and 80% by weight of the total solid PC wastes for bituminous, subbituminous and lignite coals respectively. However, it should be noted that this difference in the solid waste volumes would be reduced or eliminated, if the plants are able to sell some or most of their wastes for industrial use.

Consistent with the PC plants, the water balance is estimated for IGCC plants using the DOE report as the basis.[44] Exhibit 3-23 presents the results for two gasifiers from the DOE report. The results are rounded, and in the GE Energy case the DOE totals did not match. The GE Energy DOE case is for the radiant-convective gasifier option. The alternative GE quench technology is a less efficient, lower cost version of the technology, which was not used.

Exhibit 3-23, Summary of IGCC Plant Water Balances
U.S. DOE/NETL Study Results

	GE Energy	Shell
Plant Gross Output, MW	673.85	633.54
Plant Heat Rate (HHV) , Btu/kWh	8,668	8,503
Water Source	Gallon per Minute	
Coal Moisture	48	44
Combustion of Hydrogen in GT	483	332
Combustion of Hydrogen in Incinerator	NA	17
Combustion Air for GT	78	84
Combustion Air for Incinerator	21	0.7
Raw Water Use	7,143	6,668
TOTAL	7,772	7,145
Water Loss		
Coal Drying Moisture	NA	30
Gasification Shift	159	54
Ash Handling Blowdown	80	70
Water With Slag	32	33
COS Hydrolysis	0.3	2
GT Flue Gas	743	675
Incinerator Flue Gas	NA	14
Sour Water Blowdown	NA	41
Water Treatment Discharge	5	NA
Cooling Tower Blowdown	2,222	2,055
Cooling Tower Evaporation	4,511	4,172
Hot Water Blowdown	10	NA
Moisture in Air Separation Vent	21	NA
TOTAL	7,782	7,144

[44] Power Plant Water Usage and Loss Study, U.S. DOE NETL, August 2005.

Exhibit 3-24 presents the water balances for the present study IGCC technologies and coals. Consistent with the PC plant estimates, the DOE data was adjusted using the heat rates and gross outputs of the several plants. Coal moisture and for Shell, coal drying moisture, is based on the study coal properties.

Exhibit 3-24, Estimated Water Balances for IGCC Plants and Coals
Gallon per Minute

Gasification Technology	Slurry Fed Gasifier	Slurry Fed Gasifier	Dry Fed Gasifier
Study Coal	High Sulfur Bituminous	Low Sulfur Sub-Bituminous	Lignite
Plant Gross Output, MW	564	575	580
Plant Heat Rate Btu/kWh	8,167	8,520	8,707
Water Source	Gallon per Minute		
Coal Moisture	81	276	449
Combustion of Hydrogen in GT	381	405	311
Combustion of Hydrogen in Incinerator	NA	NA	16
Combustion Air for GT	62	65	79
Combustion Air for Incinerator	17	18	0.7
Raw Water Use	5,596	5,764	6,119
TOTAL	6,137	6,528	6,975
Water Loss			
Coal Drying Moisture	NA	NA	305
Gasification Shift	125	133	51
Ash Handling Blowdown	63	67	66
Water With Slag	25	27	31
COS Hydrolysis	0.2	0.3	2
GT Flue Gas	586	623	633
Incinerator Flue Gas	NA	NA	13
Sour Water Blowdown	NA	NA	38
Water Treatment Discharge	4	4	NA
Cooling Tower Blowdown	1,752	1,864	1,926
Cooling Tower Evaporation	3,557	3,784	3,910
Hot Water Blowdown	8	8	NA
Moisture in Air Separation Vent	17	18	NA
TOTAL	6,137	6,528	6,975

In comparison with the supercritical PC units, the IGCC water loss is only about 64 to 68% as great, or a saving of about 32 to 36%. Exhibit 3-25 summarizes the losses for the two technologies and the percent ratio of IGCC to the supercritical PC plant water loss.

Exhibit 3-25, Summary Comparison of IGCC and Supercritical PC Water Losses

	Bituminous	Subbituminous	Lignite
Supercritical PC, Water Loss GPM	9,569	9,667	10,290
IGCC Water Loss, GPM	6,137	6,528	6,975
Percent IGCC/SCPC	64%	68%	68%

Exhibit 3-26 presents the air permit data collected and used during the study.

Exhibit 3-26, Non-Criteria Pollutant Estimates, Air Permit Data (1 of 3 Tables)

Data Points	Fuel (some plants may use more than one coal, or blend)	Mercury (Hg)	Volatile Organic Compounds (VOC)	Chlorides (HCl)	Fluorides (HF)	Sulfur Trioxide (SO_3)	Hydrogen Sulfide (H_2S)	Reduced sulfur compounds	Ammonia (NH_3)
6	PC Units Bituminous Coal	0.14 to 3.2 lb/TBtu	0.0024 to 0.004 lb/MMBtu	0.0001 to 0.0042 lb/MMBtu	0.0001 to 0.00088 lb/MMBtu	No Data	No Data	0.00073 lb/MMBtu	5 ppm
5	PC Units Subbituminous Coal	0.45 to 13.1 lb/TBtu	0.0027 to 0.02 lb/MMBtu	0.00064 to 0.0131 lb/MMBtu	0.00049 to 1.17 lb/MMBtu	No Data	No Data	0.00073 lb/MMBtu	No Data
1	PC Units Lignite	51 lb/TBtu	0.0067 lb/MMBtu	0.0155 lb/MMBtu	0.01 lb/MMBtu	No Data	No Data	No Data	No Data
12	Data Points All Pulverized Coal Units	10	11	10	10	0	0	1	1
1	High Sulfur Bituminous Coal CFB Unit	0.000002 lb/MMBtu	0.004 lb/MMBtu	0.006 lb/MMBtu	No Data	No Data	No Data	No Data	No Data
5	IGCC Units Bituminous Coal	0.55 to 1.9 lb/trillion Btu	0.0017 to 0.006 lb/MMBtu	0.00112 lb/MMBtu	0.000092 lb/MMBtu	No Data	No Data	No Data	No Data
5	Data Points IGCC Units	5	5	1	1	0	0	0	0

Exhibit 3-26, Non-Criteria Pollutant Estimates, Air Permit Data (2 of 3 Tables)

Data Points	Fuel (some plants may use more than one coal, or blend)	Arsenic (As)	Beryllium (Be)	Manganese (Mn)	Cadmium (Cd)	Chromium (Cr)	Formaldehyde	Nickel (Ni)	Silica (Si)
6	PC Units Bituminous Coal	0.883 to 5.99 lb/TBtu	0.35 to 1.14 lb/TBtu	12.3 to 20.92 lb/TBtu	0.365 to 1.1 lb/TBtu	8.9 to 10.48 lb/TBtu	48.0 lb/TBtu	8.41 lb/TBtu	No Data
5	PC Units Subbituminous Coal	25.0 lb/TBtu	2.38 lb/TBtu	3.57 lb/TBtu	3.1 lb/TBtu	16.67 lb/TBtu	15.48 lb/TBtu	16.67 lb/TBtu	No Data
1	PC Units Lignite	22.0 lb/TBtu	9.0 lb/TBtu	156 lb/TBtu	7.6 lb/TBtu	6.2 lb/TBtu	Not Data	62.0 lb/TBtu	No Data
12	Data Points All Pulverized Coal Units	3	6	3	3	3	2	2	0
1	High Sulfur Bituminous Coal CFB Unit	No Data	No Data	No Data	No Data	No Data	No Data	No Data	No Data
5	IGCC Units Bituminous Coal	0.457 to 6.0 lb/TBtu	0.062 to 0.6 lb/TBtu	4.0 to 7.02 lb/TBtu	0.415 to 5.0 lb/TBtu	1.1 to 3.48 lb/TBtu	No Data	4.51 to 310 lb/TBtu	No Data
5	Data Points IGCC Units	3	3	2	2	2	0	2	0

Exhibit 3-26, Non-Criteria Pollutant Estimates, Air Permit Data (3 of 3 Tables)

Data Points	Fuel (some plants may use more than one coal, or blend)	Selenium (Se)	Vanadium (V)	Total Reduced Sulfur (TRS)	Opacity	Sulfuric acid mist emissions
6	PC Units Bituminous Coal Wet FGD	48.54 lb/TBtu	No Data	0.00073 lb/MMBtu	10 to 20%	0.0044 to 0.014 lb/MMBtu
5	PC Units Subbituminous Coal Spray Dryer	No Data	No Data	0.00073 lb/MMBtu	10%	0.0042 to 0.0061 lb/MMBtu
1	PC Units Lignite	1,370 lb/TBtu	267.0 lb/TBtu	No Data	15%	No Data
12	Data Points All Pulverized Coal Units	2	1	1	5	10
1	High Sulfur Bituminous Coal CFB Unit	No Data	No Data	No Data	20%	No Data
5	IGCC Units Bituminous Coal	1.4 to 12.5 lb/TBtu	No Data	No Data	0 to 20%	0.0005 to 0.0042 lb/MMBtu
5	Data Points IGCC Units	2	0	0	3	3

Section 4 presents two special studies which consider the IGCC technology. The first study examines the option for including a SCR with the syngas turbine to improve NO_X control; the second examines ultra-low sulfur removal with physical solvents such as Selexol and Rectisol. The present study is a "snapshot" of the technologies at one point of time. The limits on operating experience and data for the SCR technology with IGCC synthesis gas and the potential for cost variations are documented in this section and other parts of the report. It is emphasized that any decision about SCR use and the systems required to implement that use will require detailed site-specific engineering and process design to optimize economic tradeoffs and the overall emissions including a balance between gas turbine NO_X and ammonia from the SCR. The choice between MDEA, Selexol, and Rectisol in the context of SCR for the synthesis gas is uncertain until more experience and more detailed engineering is available. This report does not express a view as to whether or when such technologies should be required in permits to construct and operate IGCC facilities.

4.1 Technical and Economic Assessment of SCR for Gasification Combined Cycle NO_X Control

The NO_X emissions from syngas-burning gas turbines are in the range of 15 to 18 ppmvd, considering the use of steam and nitrogen for diluents in the combustion process.[45] Based on this and other investigations, this study assumed 15 ppmvd as the current maximum achievable limit, for modeling purposes, but takes no position on whether this level should be required in any particular permit. GE is currently in the process of modifying the combustor design, which could lower the level of NO_X emission to upper single digit ppmvd. If a lower emission level is required, e.g., in the two to three ppmvd range, then it would only be achievable through the use of a post-combustion control method, such as SCR.

Informal discussions with SCR providers confirm that the SCR system could reduce NO_X emissions from the IGCC system to about three ppmvd without a major impact on other IGCC performance. This study uses three ppmvd as the maximum achievable limit for syngas turbines with SCR, but takes no position on whether this level should be required in any particular permit. Sulfur content in the syngas is a concern for SCR installations and from the discussions with SCR suppliers, acceptable sulfur content at the inlet of the SCR would be in the 15 to 20 ppmvd range or lower. A high efficiency sulfur removal process, such as Selexol, can achieve this level provided there is a COS Hydrolysis Unit upstream. If a SCR is not used, the suppliers recommend sulfur content around 40 ppmvd is acceptable in the syngas for the combined cycle. Without a SCR, the sulfur content limit will depend on the HRSG design exit temperature and other factors that could cause corrosion or fouling in the cool, back end of the HRSG. The base case MDEA process should be able to limit the syngas sulfur content to 40 ppmvd. The MDEA process is also the least costly option and thus more likely to be acceptable from an economic standpoint.

[45] Discussions between Nexant and GE Energy, July 2005.

There are no existing coal-fired IGCC plants with SCR installed. The Japanese have a ConnocoPhillips based IGCC fueled by refinery bottoms (asphalt) that does include a SCR with the combined cycle. Several recent studies have reported and the consolidated results indicate that the SCR would increase total NO_X removal and lower the emissions from about 15 to three ppmvd.[46, 47]

PC Plant Note on SCR

In telephone discussions for this study (9/2005) with Babcock and Wilcox (B&W), they indicated a demonstrated peak NO_X removal efficiency of 95% at an undisclosed PC plant, which is significantly different than the gasification combined cycle conditions. In the same discussion B&W also provided estimates of costs for the SCR ranging from $80 to $90/kW installed at a greenfield PC plant, and $90 to $175/kW for a retrofit installation.

4.1.1 Combustion NO_X Control Technologies

Although NO_X emissions from operating IGCC power plants are quite low, stricter regulations may require control to lower levels. Available combustion-based NO_X control options for syngas-fired turbines are more limited than those available for natural gas-fired turbines. Differences between syngas and natural gas composition and combustion characteristics cause the dry low-NO_X (DLN) technology, which permits the natural gas-fired turbines to achieve emissions as low as nine ppmvd (at 15% O_2), to be inapplicable to IGCC syngas turbines. Gasification syngas differs from natural gas in terms of calorific value, gas composition, flammability characteristics, and contaminants. An IGCC plant will typically produce syngas with a heating value ranging from 250 to 400 Btu/ft^3 (HHV basis), which is considerably lower than the approximately 1,000 Btu/ft^3 for natural gas. This yields a flow rate increase compared with natural gas (approximately 14%). Also, the combustible composition of natural gas is primarily methane (CH_4), and the syngas combustible components are carbon monoxide (CO) and hydrogen (H_2). Finally, coal-derived syngas will contain higher concentrations of sulfur in the form of H_2S, which will impact use of post-combustion NO_X control.

The current NO_X control with the IGCC technology adds diluents such as steam and/or nitrogen to lower flame temperature to prevent formation of thermal NO_X. Nitrogen is available from the air separation unit at partial oxidation IGGC plants. Syngas dilution can reduce NO_X emissions levels from syngas-fired turbines to approximately 15 to 18 ppmvd (at 15% O_2). As noted earlier, GE is working to lower emissions to single digit values by improved turbine designs.

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[46] Major Environmental Aspects of Gasification-Based Power Generation Technologies, Final Report by: Jay Ratafia-Brown, Lynn Manfredo, Jeffrey Hoffmann, & Massood Ramezan for National Energy Technology Laboratory, U.S. Department of Energy, December 2002.

[47] Southern Illinois Clean Energy Center, Integrated Gasification Combined Cycle Plant and Substitute Natural Gas Methanation Plant, BACT Evaluation prepared for Steelhead Energy, LLC by Sargent & Lundy, October 2004.

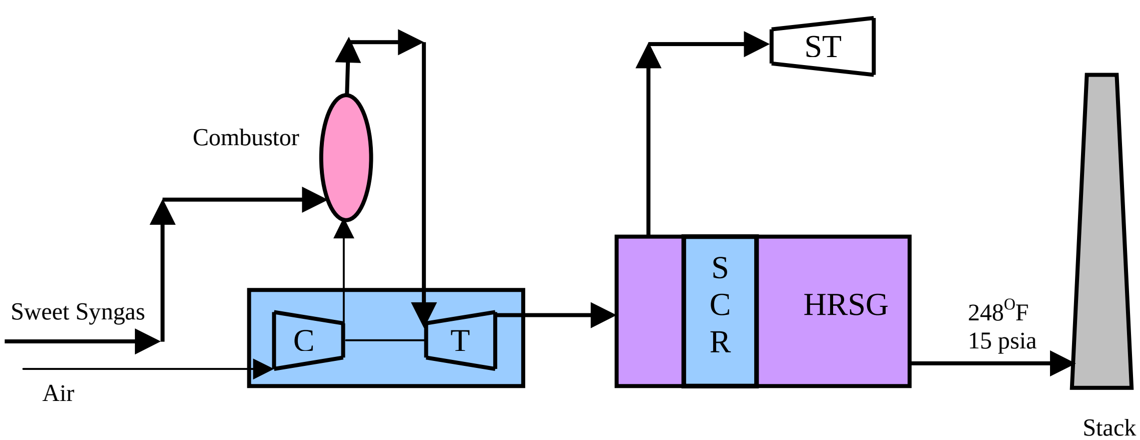
4.1.2 Post-Combustion NO_X Control

The currently available technology to achieve single-digit NO_X concentrations in the stack gas is post-combustion treatment of the flue gas which chemically reduces the NO_X to nitrogen. Selective catalytic reduction or SCR is a fully commercial technology used with natural gas-fired turbines. Variations of the natural gas SCR technology have also been installed with a number of coal-fired boilers. As noted above, there are fundamental differences between the natural gas and syngas-fired turbines that make the use of SCR with IGCC technologies more uncertain, and there are no installations at present at IGCC facilities firing coal.

Exhibit 4-1 shows how a SCR could be installed for post-combustion control at the IGCC facility. The SCR selectively reduces NO_X emissions by injecting ammonia (NH_3) into the flue gas upstream of a catalyst. The NO_X reacts with NH_3 and O_2 to form N_2 and H_2O. The SCR installation would be part of the HRSG, to allow for operation in the optimum range of temperature, about 600 to 750 ºF.

In a typical SCR ammonia injection system, anhydrous ammonia is drawn from a storage tank and evaporated using a steam- or electric-heated vaporizer. The vapor is mixed with a pressurized carrier gas to provide both sufficient momentum through the injection nozzles and effective mixing of the ammonia with the flue gases. The carrier gas is usually compressed air or steam, and the ammonia concentration in the carrier gas is about five percent. An alternative to using anhydrous ammonia is to use aqueous ammonia. The reduced ammonia concentration in an aqueous solution reduces safety concerns associated with anhydrous ammonia.

Exhibit 4-1, SCR Installation for IGCC Technology



In the informal telephone discussions with SCR suppliers, they remarked that the system could reduce NO_X below three ppmvd depending on economic considerations for the system, and also ammonia slip control. The ammonia-to-NO_X ratio can be varied to achieve the desired level of NO_X reduction. One mole of ammonia reduces one mole of NO, and two moles of ammonia reduces one mole of NO_2. Higher NH_3:NO_X ratios achieve higher NO_X emission reductions, but can result in increased un-reacted ammonia being emitted into the atmosphere. This un-reacted ammonia is known as ammonia slip. Also, SCR catalysts degrade over time, which changes the quantity of NH_3 slip. Catalyst life typically ranges from three to 10 years depending on the specific application. IGCC applications, with exhaust gas that is expected to be relatively free of contaminants, should yield a significantly longer catalyst lifetime than for a conventional coal-fired application. In the economic estimate below, four years catalyst life is set as criteria for the calculation. The four year criteria are based on engineering judgment, since no direct SCR experience with IGCC installations exist.

Installation of SCR in an IGCC's HRSG requires consideration of the environmental impacts of ammonia slip. Ammonia slip is typically limited to less than five ppmvd in most natural gas SCR applications, but may be higher if the NO_X level entering the catalyst bed is very low. Tradeoffs between NO_X and ammonia emissions show limited data, but subjectively represent problems as both emissions are pollutants and both are greenhouse gases.

There are operational impacts from the installation of a SCR system at the IGCC plant. First, the pressure loss across the SCR catalyst bed decreases gas turbine power output by approximately one-half percent and the ammonia storage and transfer equipment consumes some additional power. Second, chemical reactions may interfere with the operation of the plant. Any sulfur left in the syngas will oxidize to SO_2 and SO_3. If the sulfur in the syngas is not limited to 20 ppmvd or less and substantial levels of SO_3 are present in the flue gas, ammonia from the SCR can react with SO_3 to form ammonium salts. These salts are corrosive and sticky materials that can plug heat transfer equipment, reducing performance and increasing maintenance. Any fouling will also add to pressure drop power losses. The ammonium salts, if not deposited in the system remain in the flue gas as fine particulate matter ($PM_{2.5}$). Since a typical plant will not have particulate controls after the HRSG, the particulate emissions also need to be evaluated in the NO_X emission assessment.

In order to limit ammonium salt formation, either the ammonia slip or the SO_3 must be minimized. Some ammonia slip is inevitable, and discussions with SCR suppliers recommend a maximum of 20 ppmvd SO_2 in the syngas, or about two to three ppmvd in the flue gas going to the HRSG. While the IGCC case for the study can reduce sulfur in the syngas to about 40 ppmvd, additional cleaning such as with a physical solvent (Selexol, Rectisol) is needed to meet the 20 ppmvd sulfur limit for the syngas. Designs to balance the emissions of NO_X and ammonia slip require more detailed engineering, and the process providers were not willing to provide more data without specific design specifications.

A key factor in SCR operations is the frequency with which catalyst must be replaced to meet NO_X reduction and residual NH_3 performance targets. Until recently, catalyst replacement frequency was a source of debate between SCR control equipment suppliers and utility users. However, recent catalyst technology has made substantial advances, and catalyst suppliers are now willing to subject their product life cycles to rigorous, lengthy commercial guarantees for natural gas turbines and PC units. While there is no commercial experience with SCR and coal-fired IGCC systems, if IGCC sulfur removal is accomplished as discussed above, catalyst life cycle issues are likely to be very similar as experienced with PC units. The crucial question for IGCC will be the impact on HRSG performance of adding the SCR. This issue does not present itself for PC installations.

Although misleading, it is convenient to express the catalyst replacement frequency in terms of a single number reflecting useful catalyst life in years. In practice, a catalyst management strategy is employed to minimize the cumulative cost over the plant lifetime of providing for replacement and disposal of catalyst. Generally, a SCR unit when initially commissioned into service contains only a portion of the ultimate catalyst inventory, which after a number of years is gradually augmented with new catalyst to compensate for gradual deactivation. Ultimately, the original catalyst elements are considered "spent" and replaced with fresh catalyst, which in turn augments the older catalyst in the reactor. Specific strategies vary with site-specific design considerations.

While not completely equivalent to the issue of IGCC and SCR installations, European experience indicates that coal-fired boilers employing a proper catalyst management strategy will enjoy an average catalyst lifetime of six to10 years.[48] Vendors for Public Services New Hampshire (PSNH) Merrimack station commercial SCR installation guaranteed a catalyst life of six years; PSNH itself anticipates an eight-year life. New coal-fired boilers (e.g., U.S. Generating--Carneys Point and Stations in New Jersey) are securing vendor guarantees of a 10-year catalyst life. As noted above there is no experience with IGCC with SCR installations at this time; this is one reason for the relatively conservative life criteria selected for economic calculations. However, it appears that the operating environment for the IGCC's SCR catalyst should be less aggressive than that for the PC units and, therefore, the life may be significantly more than the four years allowed in the economic calculations.

4.1.3 Cost Estimates for SCR Addition

To consider the costs for increased NO_X control by adding the SCR to the system, the performance criteria is defined as follows based on Nexant's discussions with SCR suppliers and literature. The criteria are the basis for calculations; they are not guarantees of performance.

[48] States' Report on Electric Utility Nitrogen Oxides Reduction - Nitrogen Oxides Reduction Technology Options for Application By the Ozone Transport Assessment Group, April 1996.

- The SCR evaluation is based on the IGCC case with bituminous coal. Anhydrous ammonia is used as the SCR reagent.
- The SCR reduces NO_X from 15 to three ppmvd.
- The base performance case (15 ppmvd) is the IGCC with steam and nitrogen dilution.
- With SCR, the gas turbine gross output is assumed to be reduced by one-half percent. The SCR system also consumes additional power in vaporizing anhydrous ammonia and in ammonia pumps and blowers, which is estimated at 60 kW.
- In addition to the SCR equipment, a physical solvent system such as Selexol is assumed to be provided to meet the 20 ppmvd sulfur limit to the SCR given by the SCR suppliers. The costs for SCR addition are reported both with and without a Selexol system.
- The installed cost of the SCR is $12/kW; the total capital requirement cost is $15/kW. Cost data is from the previously referenced Southern Illinois Clean Energy Center BACT evaluation. The generating capacity at this plant would be 544 MW net.
- The plant capacity factor is assumed at 85%.

NO_X emissions for the bituminous coal IGCC case with and without SCR are summarized in Exhibit 4-2.

Exhibit 4-2, NO_x Emissions for Bituminous Coal IGCC- with and without SCR

Emission Units	NO_X Emissions – Syngas Dilution	NO_X Emissions – SCR Installed
ppmvd at 15% O_2	15	3
lb/MMBtu	0.049	0.01
lb/MWh	0.36	0.07
Tons per year	729	146

Exhibit 4-3 shows the results from estimates of the cost per ton of NO_X for installing the SCR for lower NO_X emission. A cost per ton of NO_X reduced is shown for cases with and without considering a cost for lost power generation from the added SCR power consumption. With the MDEA acid gas removal system, the cost is $7,290 per ton of NO_X removed. When Selexol technology is used to replace the MDEA process for sulfur removal, the cost per ton approximately doubles.

Exhibit 4-3, Cost Effectiveness Estimate for SCR NO_X Reduction

Cost Items		Annualized Cost	Notes
SCR Capital Cost	$ 7,500,000	$ 900,000	Capital recovery at 12% and 30 year investment term
O&M Costs			
Ammonia		$ 107,400	Based on $363/ton of anhydrous ammonia[49]
Catalyst Replacement		$ 2,048,700	Based on 4 year catalyst life and a catalyst replacement cost of $396/cu.ft.[50]
Disposal Cost		$ 200,000	
Labor		$ 130,800	
Maintenance		$ 196,200	
Total O&M		$ 2,683,100	
Total O&M + Annualized Capital		$ 3,583,100	
Cost per Delta Ton Removed		$ 6,145	
Auxiliary Power Consumption		$ 668,000	Based on $0.04 per KWh
Cost per Delta Ton Removed When Aux. Power Included		$ 7,290	
Cost per Delta Ton Removed Aux. Power & Selexol Included		$ 13,120	

Due to the lack of experience with SCR application on coal-based IGCC units at this time, there are several unresolved issues that may have additional cost impacts, resulting in increases in the costs shown in Exhibit 4-3. Some of these issues are outlined below:

- Modifications to the HRSG design may become necessary to minimize adverse effects of ammonium salts formed from reaction between ammonia slip and SO_3. Such modifications have not been accounted for in the above estimates.

[49] Potash Corp Website, http://www.potashcorp.com/investor_relations/markets_information/ammonia_margins/, accessed on February 21, 2006.

[50] Catalyst cost factor used in the EPA's IPM Model, Documentation for EPA Base Case 2004 (V.2.19), EPA 430-R-05-011, September 2005.

- Without proven experience, it may not be possible to obtain proper performance guarantees and warranties for the overall SCR/HRSG installation or such guarantees/warranties may be offered at higher costs.

- The catalyst suppliers may offer catalyst life guarantees below the levels assumed for this study.

- Uncertainty exists regarding optimal ammonia slip and syngas sulfur content levels required to mitigate HRSG effects. Selection of conservative levels can have an impact on the overall costs.

The impact of the above issues would vary with the operating conditions associated with each IGCC installation. Some of these issues can have a substantial impact on the SCR costs. As an example of cost sensitivity, if the catalyst life is reduced from 4 to 3 years, the cost per ton removed will increase from $7,290 to $8,460, about a 16% change.

The Selexol process suppliers were unwilling to provide cost data without more detailed design information and payment for their efforts. However cost data is available in the literature, and from Nexant experience with other gasification projects.[51] If Selexol is required to reduce the sulfur content below the limits of an MDEA acid gas cleaning process, the increased capital cost is estimated to be $20 million. The increased annualized capital cost would be $2.40 million; increased annual O&M costs are estimated to be $1million and the cost per delta ton increases to $13,120. Costs for the MDEA system from the Texaco study were used as a check against the published Selexol incremental costs.[52]

The need to replace the amine acid gas removal system with a more effective physical solvent technology is still uncertain. From the discussions with technology suppliers, technology selection requires more detailed examination for specific coals and plant designs. In some cases, the MDEA process may be able to reduce the syngas sulfur sufficiently for the SCR (about 20 ppmvd); also, the SCR technology for coal is still evolving and may become more sulfur tolerant.

4.2 Assessment of Sulfur Removal Technologies – Selexol and Rectisol

The uncertainties associated with SCR use with IGCC syngas or more stringent SO_2 removal requirements could lead to a need for deeper cleaning of the syngas. The removal capability of the amine-based MDEA chemical sorbent acid gas cleaning process is limited by economic trade-offs, so alternative sulfur removal processes, Selexol and Rectisol, are evaluated in this section for the deeper cleaning option.

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[51] Process Screening Analysis Of Alternative Gas Treating And Sulfur Removal For Gasification, Revised Final Report, December 2002, Prepared by SFA Pacific, Inc., U.S. DOE Task Order No. 739656-00100.

[52] Texaco Gasifier IGCC Base Cases, U.S. DOE/NETL, PED-IGCC-98-001 Latest Revision June 2000.

A major advantage of the Rectisol process is its removal of COS, so that no upstream COS hydrolysis step is necessary. The major cost issue for Rectisol is its requirement for refrigeration to cool the methanol in the process to low temperature. Rectisol can reduce the syngas sulfur content to as low as two ppmvd in the treated gas. Such low levels of sulfur concentration are not needed for SCR operation discussed earlier and unless there is another technical or regulatory reason, the added costs may not be justified.

The Selexol process cannot achieve the same low sulfur concentration as Rectisol, and requires COS hydrolysis. A typical coal syngas contains five percent of its total sulfur as COS, and the physical solvents are only about half as effective removing COS compared to H_2S. However, the Selexol process may be less complex and does not require cryogenic operating temperature as the Rectisol process does. To obtain sulfur removal for the SCR addition, Selexol may not need refrigeration equipment. The low temperature criterion adds to the energy penalty associated with the Rectisol process.

Exhibit 4-4 shows a comparison of the three technologies described above from the previously referenced Southern Illinois Clean Energy Center BACT evaluation based on an Illinois #6, high sulfur bituminous coal similar to this study's bituminous coal case.

Exhibit 4-4, Comparison of Sulfur Removal Technologies for IGCC

Sulfur Removal Technology	Syngas Sulfur Compounds Concentration ppmvd	SO_2 Emissions lb/MMBtu	Percent Reduction from Uncontrolled Emission %
MDEA Chemical Solvent	75	0.033	99.37
Selexol Physical Solvent	20	0.009	99.83
Rectisol Physical Solvent	10	0.0045	99.91

While the differences in Exhibit 4-4 appear small, for a point of reference if the uncontrolled SO_2 emissions were 100,000 tons per year, the emissions after applying each of the above technologies would be 630, 170 and 80 tons per year – the reductions achieved improve by a factor of eight, comparing the lowest controlled emission rates to the highest.

While the process developers would not provide cost data without a detailed design basis, according to the Rectisol (Linde) and Selexol (UOP) suppliers, sulfur content of the coal and thus the raw syngas is not a significant factor for removal efficiency and has a limited impact on costs.

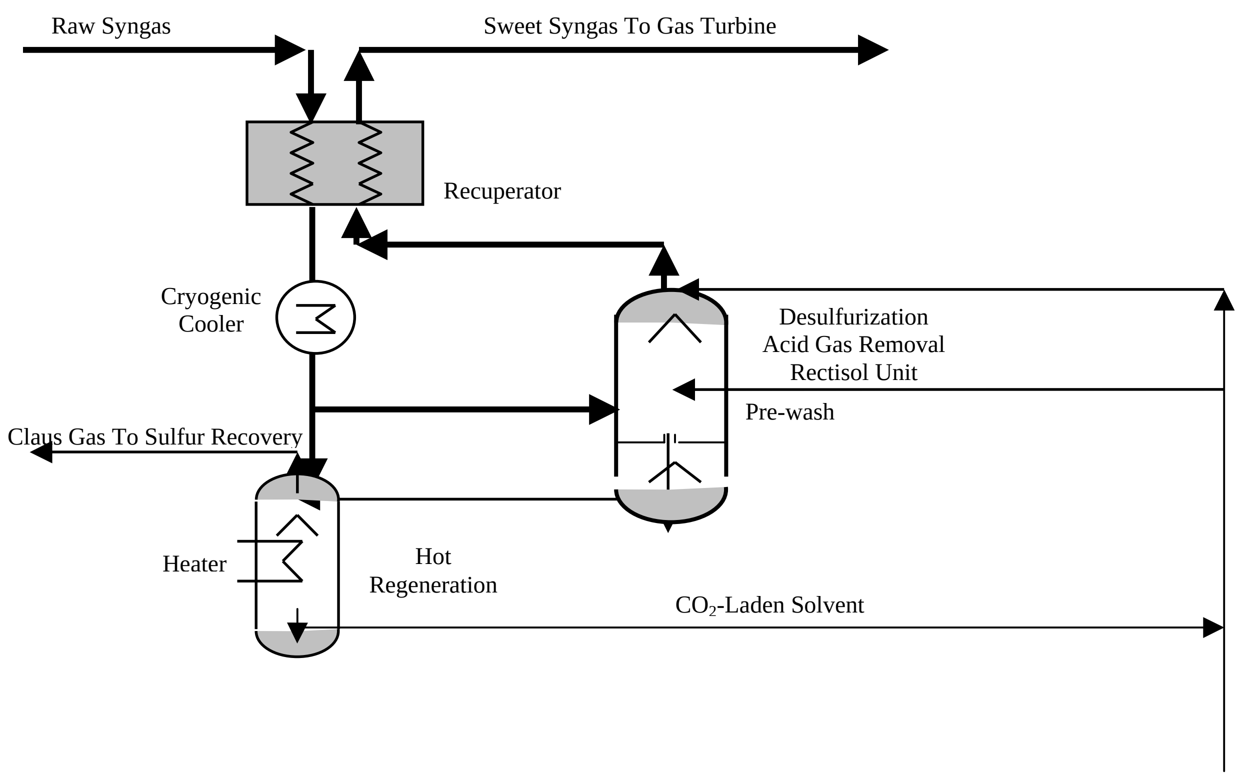
4.2.1 Sulfur Removal and Recovery Technologies

As mentioned earlier, in an acid gas removal process syngas is treated via contact with a solvent to remove H_2S and some CO_2. Physical solvents, such as Rectisol and Selexol are favored over chemical solvents when the sulfur content of the clean gas must be very low, such as for chemical plant operations. The removed H_2S is treated in a Claus process to recover sulfur similar to the other IGCC cases.

Rectisol Process

A simplified flow diagram of the Rectisol process is shown in Exhibit 4-5. The Rectisol process uses methanol as a physical solvent operating at cryogenic temperature for removal of acid gases. The feed gas is pre-cooled. The injected methanol plus water is separated from the gas, which is given into the wash column. H_2S and some CO_2 are physically absorbed from the raw gas by the cooled solvent. Sulfur is removed in this column down to < 10 ppmvd; the CO_2 slip is approximately 60-65%, meaning that approximately 35 - 40% of the incoming CO_2 is removed. H_2S is then desorbed by re-boiling the solvent. The CO_2-laden solvent is recycled back to the Rectisol unit. The released H_2S-loaded gas is sent to the sulfur recovery process (Claus process).

Exhibit 4-5, Rectisol Process Block Diagram



Selexol Process

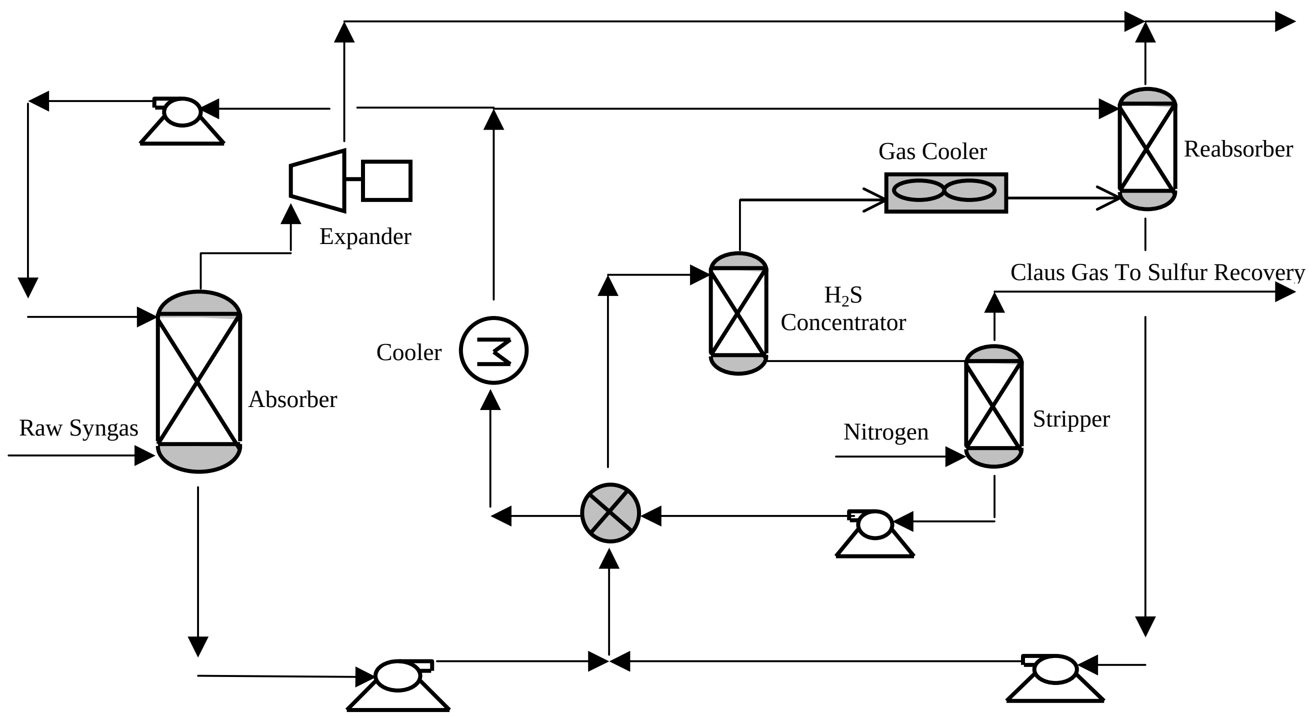
Selexol is a liquid physical solvent developed by Allied Signal in the 1950s, and is used for treating natural and synthesis gas streams. The solvent is used in more than 100 applications for the removal of H_2S, CO_2, mercaptans, and for both hydrocarbon and water-dew point control. The Selexol technology is currently owned by Union Carbide Corporation. Union Carbide has granted exclusive rights to UOP for licensing Selexol technology in the field of partial oxidation. In December 2005, Honeywell completed acquisition of UOP.

A simplified flow diagram of the Selexol process is shown in Exhibit 4-6. Untreated syngas is sent to the absorber, where it contacts cooled regenerated solvent, which enters at the top of the tower. In the absorber, H_2S, COS, CO_2 and other gases such as hydrogen, are transferred from the gas phase to the liquid phase. The treated gas exits the absorber and is sent out of the Selexol unit battery limits. The solvent streams from the absorber and re-absorber are treated rich solvent, and are combined and sent to the lean/rich exchanger. The solvent from the re-absorber is sent via the rich pump.

In the lean/rich exchanger the temperature of the rich solvent is increased by heat exchange with the lean solvent. The rich solvent is then sent to the H_2S concentrator, where a portion of the CO_2, CO, H_2 and other gases are stripped from the solvent. Nitrogen from the air separation unit is the stripping medium. The temperature of the overhead stream from the H_2S concentrator is reduced in the stripped gas cooler, and is sent to the re-absorber, where H_2S, COS and a portion of the other gases are transferred to the liquid phase. The stream from the re-absorber exits the unit battery limits.

The rich solvent from the re-absorber is combined with rich solvent from the absorber, as described above. The partially regenerated solvent exits the H_2S concentrator and is sent to the stripper, where the solvent is regenerated. The lean solvent is then sent to the other side of the lean/rich exchanger via the lean pump. The temperature of the lean solvent is further reduced in the lean solvent cooler. A portion of the lean solvent is then sent to the re-absorber, while the remainder is sent to the top of the absorber via the lean booster pump. Hydrogenated tail gas from the sulfur recovery unit is recycled back to the acid gas removal unit and enters with the feed to the re-absorber (not shown).

Exhibit 4-6, Selexol Process Block Diagram

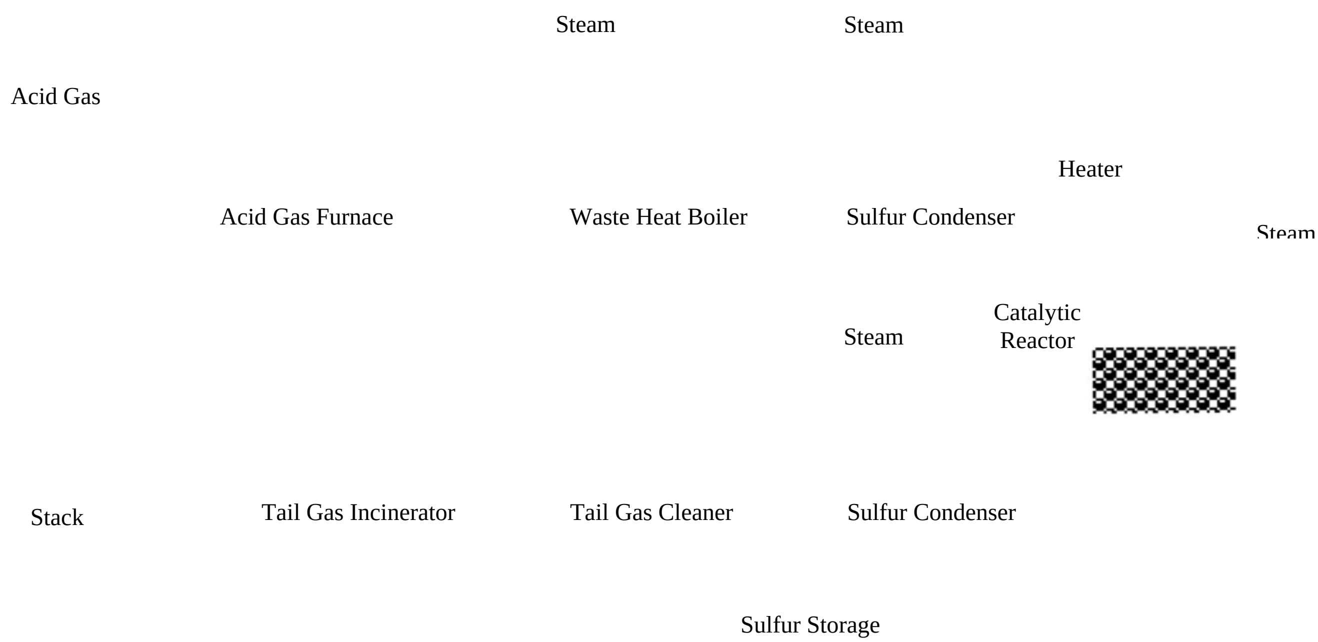


Sulfur Recovery

A simplified flow diagram of the Claus sulfur recovery process is shown in Exhibit 4-7. The Claus process produces elemental sulfur by burning in a furnace part of the H_2S to form SO_2, and by reacting un-combusted H_2S with SO_2. One-third of H_2S in the feed gas is oxidized to SO_2. Simultaneously, an un-catalyzed reaction occurs between the SO_2 and unburned H_2S, which are in stoichiometric ratio, converting about 60% of each to sulfur vapor. The gas, upon leaving the furnace, is then cooled to condense sulfur, reheated, and passed through a catalytic converter. A three-converter system recovers about 98% of the sulfur. The gas leaving the catalytic converter is sent to a tail gas cleaning unit (TGCU), which is generally a Shell Claus Off-gas Treatment (SCOT) process.

The SCOT process consists of two sections. In the first section, the tail gas is heated and reacted with H_2 over a catalyst. All sulfur compounds are converted to H_2S. The off-gas is then cooled in a waste heat boiler followed by a water quench. Finally, H_2S is selectively absorbed by an MDEA. The rich amine solution is stripped and the H_2S-rich stream is recycled to the front end of the Claus plant. The treated gas from the SCOT absorber is incinerated and the incinerated gas is discharged through a high stack.

Exhibit 4-7, Sulfur Recovery Block Diagram



4.2.2 Cost and Economic Estimates

The Selexol and Rectisol technology suppliers, UOP LLC and Linde Group respectively, were not able to provide cost information without a more detailed design basis and compensation for their efforts.

Other sources for costs were pursued and the results are reported below.

- Eastman Gasification Services Company in an October 2003 presentation to the Eastern Tennessee section of the AIChE, "Coal Gasification – Today's Technology of Choice and Tomorrow's Bright Promise" reported estimated costs of \$20 million for Selexol and \$40 million for Rectisol. Plant size is not given, so only the cost factor of 2 in estimating the difference between Selexol and Rectisol is useful. However, an article in Power magazine reports similar information and describes the cost for an IGCC of approximately 500 MW.[53] The absolute cost values are for costs above what is estimated for an MDEA alternative system.

- The previously referenced Southern Illinois Clean Energy Center BACT evaluation also provides estimates for a Selexol system to be installed on a 544 MW IGCC plant. All costs are provided as incremental costs (over an MDEA system). The total capital

[53] Vol. 148, No. 2 March 2004 Power Magazine, "Coal Gasification: Ready for Prime Time" – Available at URL: http://www.businessweek.com/pdf/240648PWRePrint.pdf, accessed February 23, 2006.

cost for the Selexol system addition is estimated at approximately \$40 million (\$75/kW). The annual operating costs are estimated at approximately \$6 million. The overall cost effectiveness is estimated at approximately \$22,000 to \$30,000 per ton of NOx removed, compared to the base case MDEA.

- The above BACT evaluation also includes addition of a Rectisol system to the same 544 MW IGCC plant. The incremental cost estimates provided show a capital cost of \$81 million (\$149/kW) and operating costs of \$8.3 million.

As part of the study scope of work, a summary of technologies and current status for carbon dioxide (CO_2) separation, capture and sequestration was prepared and documented in this section.

5.1 CO_2 Separation, Capture and Sequestration Background

While CO_2 is not a regulated power plant emission, the strong scientific and political focus on how CO_2 impacts global climate has initiated a number of technical and economic assessments of technologies that could be installed to separate, capture and sequester (SCS) the gas for hundreds or thousands of years. SCS technologies and estimates of their performance and economics are discussed in this section of the report. The discussion focuses upon technologies that are likely to be commercially demonstrated in the 2010 time period.

While industry and government research is working diligently to reduce the cost and improve performance of SCS technologies, the timing of their wide-spread introduction into the commercial market is highly uncertain. Aside from economic considerations, the major implementation issue is the location, definition and justification of geological sequestration formations. The task of convincing the public, government and industry stakeholders that sequestration is safe and environmentally sound is difficult. Except for limited opportunities for enhanced oil or gas recovery operations in existing and geologically well defined-sites, the storage of very large amounts of CO_2 for hundreds of years will need to be carefully tested, demonstrated and monitored before the technology is accepted by enough stakeholders to allow the technology to move forward at the scale that is needed for serious power generation carbon management.

The CO_2 separation and capture technologies for power generation systems are traditionally split into “post-combustion and pre-combustion” categories. Capture of CO_2 from flue gases produced from combustion of fossil fuels, such as in a PC boiler, is referred to as post-combustion capture. A chemical sorbent process would normally be used for CO_2 capture for this purpose.

The concept of combusting coals (or other fuels) with oxygen instead of air can be classified as a SCS process that falls in the post-combustion category. This process is applicable to PC boilers and is in early stages of development. The process results in a flue gas stream that is mainly CO_2 and H_2O, making it possible to capture and sequester CO_2 at relatively low cost.

Pre-combustion usually means the application of gasification to produce a synthetic gas and then treatment of this gas to produce and capture CO_2, resulting in a stream of hydrogen-rich fuel that can be used for various applications, including power generation. Capturing of CO_2 is generally accomplished using a physical or chemical absorption process.

5.2 SCS Technologies for Pulverized Coal Power Plants

Post-combustion CO_2 separation and capture from PC plant flue gas (mainly by amine chemical absorption) is currently being examined by industry. While the amine process is technically proven in small-scale commercial operations, the economics and scale-up issues associated with a 500 MW or larger power plant are substantial.

5.2.1 Gas Absorption

Gas absorption processes are commonly used in commercial industrial operations to remove CO_2 from mixed-gas streams. Gas absorption can treat streams at widely ranging pressures and CO_2 concentrations. Typically gas absorption works by contacting the mixed-gas stream containing CO_2 with a liquid solvent in which CO_2 is soluble. Two types of solvents are used for CO_2 removal: physical solvents and chemically reactive solvents. Physical solvents follow Henry's law such that the mass of a gas that will dissolve into a solution is directly proportional to the partial pressure of that gas above the solution. Therefore, physical solvents are more suitable for gas streams that are under high pressure; resulting in an elevated CO_2 partial pressure. This increases CO_2 solubility, which, in turn, reduces the solvent circulation rate. Chemically reactive solvents first dissolve CO_2 and then react with it. Pressure has a secondary effect on the performance of chemically reactive solvents.

If the mixed-gas stream containing CO_2 is at elevated pressure, the physical solvent can be recovered and the CO_2 separated by simply flashing the gases to a lower pressure. Chemically reactive solvents require energy to reverse the chemical reaction to recover the dissolved gases. Commercial experience indicates that the physical solvent process is more economical if the CO_2 partial pressure is above 200 psia. At low-inlet CO_2 partial pressure such as a PC plant flue gas, chemically reactive solvent processes are required.

Some of the commonly used commercial gas absorption processes are listed in Exhibit 5-1. The first four processes use solvents that physically absorb the CO_2 and are applied to mixed gas streams under high pressure that contain a high concentration of CO_2. The solvent circulation rates for these processes are generally higher than for chemical absorption. For the three other processes, a chemically reactive solvent is used.

Alkanolamines are a group of amines that are used for CO_2 removal. They include monoethanolamine (MEA), diethanolamine (DEA), diglycolamine (DGA), diisopropanolamine (DIPA), and triethanolamine (TEA). Of these, MEA is the most alkaline; it has the highest dissociation constant and the highest pH in water solution. The others are progressively less alkaline in the order listed. Other properties that bear on the use of these amines follow in the same order as their alkalinities. The primary amines (MEA) form the most stable bond with the acid gas, followed by the secondary amines. The least stable bond is formed by the tertiary amines. Therefore, amine-based processes are the most common and are considered to be the best technology for the removal of CO_2 from PC flue gas with low CO_2 partial pressure.

Exhibit 5-1, Gas Absorption Processes Used for CO_2 Removal

Process	Owner	Application
Physical Solvents		
Sulfinol	Shell Oil Company	Natural gas, refinery gases and synthesis gases
Selexol	Universal Oil Products	Natural gas, refinery gases, and synthesis gases
Rectisol	Lurgi GmbH and Linde AG	Heavy oil partial oxidation process of Shell and Texaco; also Lurgi gasification
Purisol	Lurgi GmbH	Natural gas, hydrogen, and synthesis gases
Chemical Solvents		
Catacarb	Eickmeyer & Associates, Kansas	Any mixed-gas stream
Benfield	Universal Oil Products	Synthesis gas, hydrogen, natural gas, town gas, and others
Amines (alkanolamines and hindered amines)	Both generic solvents and proprietary formulations with additives	Any mixed-gas stream

In addition to the primary commercial process of absorption with MEA, there are other separation technologies under research and development including:

- Cryogenic Cooling
- Gas Separation Membranes
- Gas Absorption Membranes
- Gas Adsorption

None of the processes have been used at or near the scale of CO_2 removal required by large power generation plants, and most of the R&D is focused on natural gas-fired systems. The MEA process is judged the only process likely to be available in the study's timeframe for coal-fired plants and is discussed in more detail below.

5.2.2 MEA Absorption

For removal of CO_2 from low-pressure, low-CO_2 concentration pulverized coal flue gases, MEA scrubbing is considered state-of-the-art for fossil fuel-fired systems such as coal-fired boilers and gas turbines. A few commercial facilities use MEA-based solvents to capture CO_2 from coal, fuel oil, and natural gas flue gas streams for use in the food industry. However, these plant capacities are roughly 100 to 1,000 tons/day compared to more than 5,000 tons/day for a 500-MW coal-fired plant.

The low CO_2 partial pressure necessitates the use of MEA-based systems, and while MEA has the advantage of fast reaction rate with CO_2 at low partial pressures compared to other commercially available amines, there are significant disadvantages such as high heat of reaction, limited capacity and significant corrosion problems. Oxygen present in the flue gas causes rapid degradation of alkanolamines. The degradation byproducts lead to corrosion problems and cause significant deterioration in the overall separation performance. To counter the influence of oxygen, the approach currently practiced is the use of chemical inhibitors. For example, the processes licensed by Kerr-McGee/ABB Lummus Global Inc. and by Fluor Daniel use inhibited monoethanolamine solutions.[54, 55]

Commercial providers of MEA technology also include Praxair and Mitsubishi Heavy Industries (MHI). Recent advances in chemical solvents have included the commercial introduction of the KS-family of hindered amines by MHI. Their different molecular structures allow enhanced reactivity toward a specific gas component, in this instance CO_2. Benefits of these advanced amines in addition to extensive heat integration include the following: 1.) Higher absorption capacity (only one mole of hindered amine is required to react with 1 mol CO_2 compared with two moles MEA), 2.) 90% less solvent degradation, 3.) 20% lower regeneration energy, 4.) 15% less power, 5.) 40% lower solvent recirculation rates due to higher net absorption capacity, 6.) Lower regeneration temperature, 7.) less corrosion in the presence of dissolved oxygen, and 8.) Lower chemical additive cost. An example of a coal-fired power plant system employing an MEA process for CO_2 capture is presented in Exhibit 5-2 and briefly described below.

The flue gas is partially compressed to 17.5 psia by a centrifugal blower to overcome the gas-path pressure drop. The flue gas enters the absorber and flows upward and counter to the lean MEA solution. CO_2 is removed from the flue gas in the packed-bed absorber column through direct contact with MEA. The CO_2-depleted flue gas is exhausted to the atmosphere. The CO_2-rich solution is heated in a MEA rich/lean heat exchanger and sent to the stripper unit where low-pressure steam from the steam turbine (in a power plant) provides the thermal energy to liberate the CO_2. The CO_2 vapor is cooled to condense water and then sent to a multistage compressor where the CO_2 is compressed to a super-critical state of about 1,200 psia for pipeline transport. The CO_2 laden stream is further dehydrated using glycol or molecular sieve processes.

[54] Barchas, R. and Davis, R. The Kerr-McGee/ABB Lummus Crest Technology for the Recovery of CO2 from Stack Gases. Energy Conversion Management, 33(5-8), p. 333, 1992.
[55] Sander, M.T. and Mariz, C.L. 1992. The Fluor Daniel Econamine FG Process: Past Experience and Present Day Focus. Energy Conversion Management, 33(5- 8), p. 341, 1992.

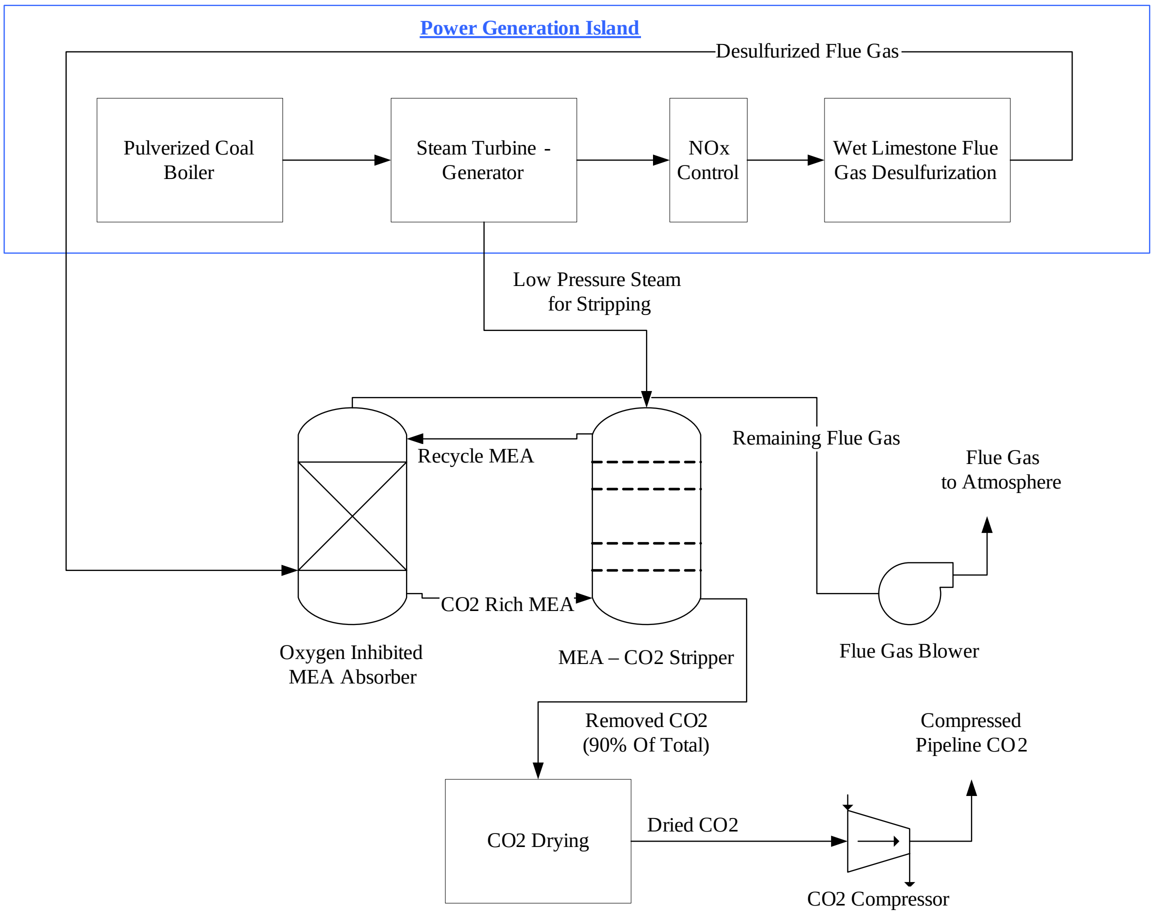


Exhibit 5-2, CO_2 Removal by MEA Absorber/Stripper

5.2.3 MEA CO_2 Absorption Performance

The MEA process can practically achieve recoveries of 85% to 95%, with CO_2 purities over 99% by volume. However, the MEA process requires large amounts of thermal energy (heat/steam) as well as auxiliary power to operate pumps and blowers for gas and solvent circulation. Depending on the exact concentration of the solution, the steam consumption can vary from 1,200 to 1,620 Btu per pound of CO_2 recovered. To prevent corrosion, the flue gas is treated so that SO_2 is below 10 ppmvd, NO_2 is below 20 ppmvd, and NO_X is below 400 ppmvd. Solvent degradation and losses also occur during the regeneration operation.

Recent U.S. DOE NETL and other studies indicate that the overall energy penalty associated with CO_2 separation and capture with an amine solution plus compression of the CO_2 gas ranges from 10 to 15% of the design capacity of a PC power plant without

CO_2 SCS.[56] For supercritical PC (SCPC) plants with and without CO_2 removal examined in the DOE study the major performance differences are illustrated in Exhibit 5-3.

Exhibit 5-3, U.S. DOE/NETL Study, CO_2 Removal Impacts – A Supercritical PC Plant

Performance	SCPC without CO_2 Removal	SCPC with CO_2 Removal
Gross Plant Power, MW	491.1	402.3
Total Auxiliary Power Requirement, MW	29.1	72.7
Net Plant Power, MW	462	329.3
Net Efficiency, % HHV	40.5	28.9
Net Heat Rate, Btu/kWh	8,421	11,816
Coal Feed, lb/hour	333,542	333,542

The main systems requiring increased auxiliary power are the larger induced draft flue gas blower (some 20 MW) required for the MEA removal process, and the CO_2 compression (about 30 MW). In addition, the large decrease in net efficiency is a result of amine solvent regeneration via steam stripping. This requires a significant amount of low pressure steam to be by-passed from the low pressure steam turbine, thereby preventing power generation. In the industry methodology for comparing technologies, this is accounted for in costs for equipment, and by calculating the "avoided cost" for CO_2 removal, which includes costs to replace the power lost by installing the removal system.

5.2.4 MEA Technology Status

Most of the new work and advances to the amine absorption technology have focused on natural gas-fired systems[57,58]. Other sources provide data for natural gas-fired systems and some of that information is summarized here in exhibits 5-4 and 5-5.[59] The performance data in Exhibit 5-4 is based on the fuel lower heating value (LHV). While this work has indicated significantly reduced costs and improved performance, the development of similar systems for PC plants does not appear to be progressing very rapidly.

[56] Evaluation of Innovative Fossil fuel Power Plants with CO2 Removal, U.S. DOE/NETL and EPRI, Prepared by ParsonsEnergy and Chemicals Group, December 2000 – updated 2002.

[57] Daniel Chinn, Dag Eimer, and Paul Hurst, CO2 Capture Project: Post-Combustion "Best Integrated Technology" (BIT) Overview, presented at the Third National Conference on Carbon Capture and Sequestration, National Energy Technology Laboratory/Department of Energy, Alexandria, VA, May 3-7, 2004.

[58] M. Simmonds, et al., "Post Combustion Technologies for CO2 Capture: A Techno-Economic Overview Of Selected Options", uregina.ca/ghgt7/PDF/papers/nonpeer/471.pdf, Accessed June 28, 2006.

[59] Gasification Plant Cost and Performance Optimization Project, U.S. DOE/NETL Contract No. DE-AC26-99FT40342, September 2003, prepared by Nexant, Inc., Bechtel Corporation and Global Energy.

Exhibit 5-4, Natural Gas Combined Cycle CO_2 Capture Progress

Study Basis	Net Power, MW	Efficiency, LHV %	Capital Cost, $ millions	Operating Cost $ millions	CO_2 Avoided Cost $/ton
Natural Gas Combined Cycle Without CO_2 Capture	392	57.6	284	13	NA
Baseline Capture Study	322	47.3	418	26	60
Low-cost Capture Study	332	48.8	366	24	45
Low-cost Integrated Capture Study	335	50.6	345	24	35
Best Integration (BIT) Study	357	52.5	352	21	28

Exhibit 5-5, Solvents for CO_2 Removal

Supplier	Solvent	Solvent Loss, lb/ton of CO_2	Solvent Cost, $/lb	Solvent Cost, $ per ton of CO_2	Steam Use, ton per ton of CO_2
Non Proprietary	MEA	2 to 6	0.60	1.20 to 3.50	2
Econamine, Fluor	MEA plus Inhibitors	3.2	0.70	2.30	2.3
KS-1, MHI	Hindered Amines	0.7	2.30	1.55	1.5
PSR, Amit Chakma	Amine Mix	0.2 to 1.8	unknown	unknown	1.1 to 1.7

Research organizations, including U.S. DOE and industry, are concentrating efforts on non-amine processes such as ammonia scrubbing, membrane separation and oxygen combustion as possible methods to separate and capture CO_2 at PC plants. The following is from the DOE web site and indicates the difficulty of sequestration of CO_2 at coal-fire plants.[60] *"Pulverized coal (PC) plants, which are 99 percent of all coal-fired power plants in the United States, burn coal in air to raise steam. CO_2 is exhausted in the flue gas at atmospheric pressure and a concentration of 10-15 volume percent. This is a challenging application for CO_2 capture because:*

- *The low pressure and dilute concentration dictate a high actual volume of gas to be treated*
- *Trace impurities in the flue gas tend to reduce the effectiveness of the CO_2 adsorbing processes*

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[60] NETL Website, Carbon Sequestration, http://www.netl.doe.gov/technologies/carbon_seq/core_rd/co2capture.html, accessed February 13, 2006.

- *Compressing captured CO_2 from atmospheric pressure to pipeline pressure (1,200 - 2,000 pounds per square inch (psi)) represents a large parasitic load.*

Aqueous amines are the state-of-the-art technology for CO_2 capture for PC power plants. Analysis conducted at NETL shows that CO_2 capture and compression using amines raises the cost of electricity from a newly-built supercritical PC power plant by 84 percent, from 4.9 cents/kWh to 9.0 cents/kWh. The goal for advanced CO_2 capture systems is that CO_2 capture and compression added to a newly constructed power plant increases the cost of electricity by no more than 20 percent compared to a no-capture case."

Results from a 2000 DOE/Alstom Power study showed that capturing 90% of the flue gas CO_2 from an existing pulverized coal power plant (using conventional amines) has significant performance and economic impacts.[61] The results of the study show plant efficiency dropping from 35% to 21% with MEA and to 23% with combined MEA – MDEA, all based on the coal higher heating values.

5.3 Oxygen Combustion Technology

Substitution of oxygen for all or part of the combustion air for PC boiler (and other combustion devices including fluid bed furnaces and gas turbines) has been proposed in some concepts as a method to produce a CO_2-rich flue gas requiring no separation and that could be directly sequestered. Conventional air combustion processes in boilers or gas turbines produce flue gases that contain predominantly nitrogen (>80 vol%) and excess oxygen in addition to CO_2 and water. If oxygen rather than air is used as the combustion source and nitrogen is replaced with re-circulated CO_2, the nitrogen content of the flue gas approaches zero (assuming minimal air leakage into the system) and the flue gas contains predominantly CO_2 with a small amount of excess oxygen and water. Circulating a part of the recovered CO_2 controls the adiabatic flame temperature.

While schemes for oxygen combustion (or oxycombustion), usually with the recycle of flue gas for combustion control, have been conceptually examined, there are no units in operation. Commercial plant feasibility may be difficult to justify under most conditions because of the auxiliary power consumption of the air separation unit needed to produce the oxygen. The Canadian Clean Power Coalition (CCPC) and other Canadian organizations have performed significant study and tests with oxygen combustion.[62, 63] These investigations show higher costs and reduced performance compared to both gasification with CO_2 removal and amine CO_2 removal options.

[61] Engineering Feasibility and Economics of CO2 Capture on an Existing Coal-Fired Power Plant, Alstom Power, ABB Lummus Global, and American Electric Power; prepared for the Ohio Coal Development Office and U.S. DOE contract DE-FC26-99FT40576, June 2001.
[62] CCPC Phase I Executive Summary, Summary Report on the Phase I Feasibility Studies conducted by the Canadian Clean Power Coalition, May 2004.
[63] Summary of Canadian Clean Power Coalition work on CO2 capture and storage by Geoffrey F Morrison, August 2004. IEA Clean Coal Centre.

One of the goals of research being conducted on oxycombustion technology is to lower the cost of air separation, which is expected to bring the overall cost of this technology closer to the carbon capture costs with gasification[64]. U.S. DOE just recently (November 2005) announced awards for two oxygen combustion related projects totaling nearly $10 million[65]. These projects are expected to help expedite the timeline for commercialization of oxycombustion technology through slip stream or pilot plant testing.

5.4 Coal Gasification with CO_2 Removal

Gasification technology developers and other proponents of coal gasification for production of electric power and co-production concepts are strongly focused on the potential advantages of gasification when combined with requirements for CO_2 separation, capture and treatment for transport to sequestration sites. Technology developers hope that the CO_2 issue will lead to greater introduction of gasification combine cycle (GCC) technology into the power generation market than has occurred in the past. A number of large scale gasification units have been installed globally, but the great preponderance of the installations are at petroleum refinery operations or chemical plants where often inexpensive fuels, a process need for synthesis gas (CO and hydrogen), and the in-plant need for power and thermal energy may all exist. Despite demonstrations of IGCC power plants in North America and internationally, industry has resisted commercial applications for some 30 years. The major issues preventing wider acceptance are high cost, uncertainty of technology performance – especially gasifier reliability, and the traditional power generation industry's reluctance to operate what they view as more of a chemical plant than a power plant.

Exhibit 5-6 is a simplified diagram to illustrate a process for IGCC with CO_2 removal. The process is similar to the IGCC cases without CO_2 removal except that the gas from the gasifier is sent to a CO shift converter prior to cooling, and the acid gas removal system (shown here as Selexol technology) removes CO_2 as well as the sulfur compounds.

The other significant difference between the IGCC processes with and without CO_2 removal is the compression and drying of the product CO_2, which is assumed to be made ready for pipeline transportation.

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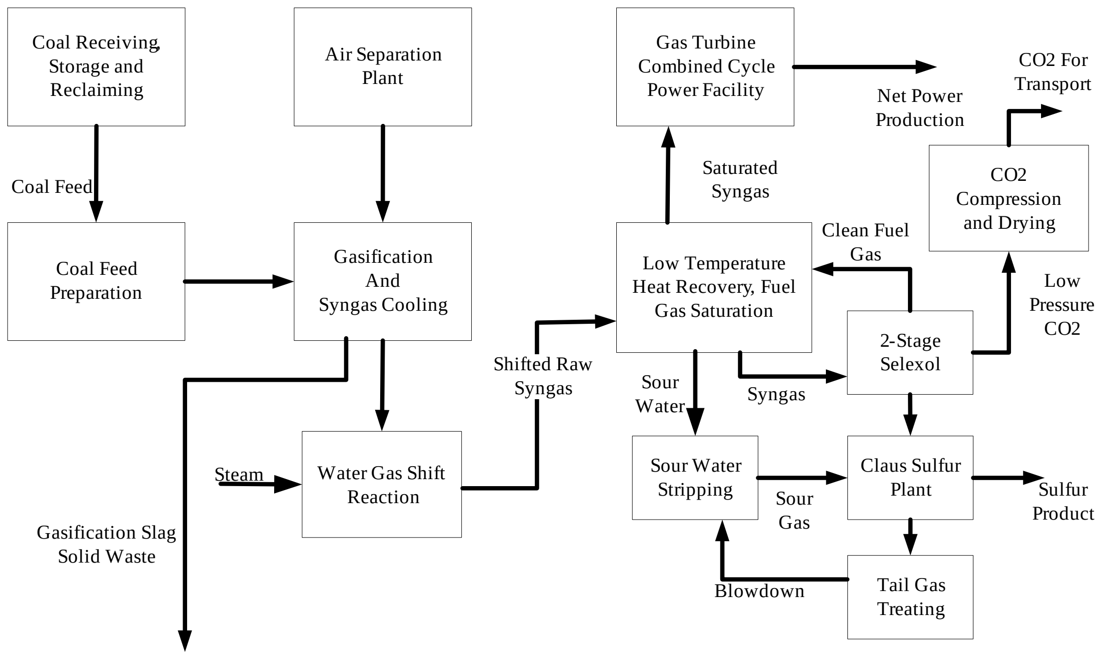
[64] F. Allix, "Today's Technologies, Tomorrow's Potential," Opening Plenary Session, 2005 Clean Coal & Power Conference, November 21-22, 2005, Washington, DC.

[65] NETL Website, Announcements, http://www.netl.doe.gov/publications/press/2005/tl_oxycombustion_award.html, Accessed on February 13, 2006.

Exhibit 5-6, IGCC with CO_2 Separation and Capture



None of the installed gasification plants are designed for the purpose of producing electric power and removing CO_2. The processes required to remove CO_2 from an IGCC plant are commercial in other gasification applications. Some work will be required to test the ability of gas turbines to use the more hydrogen rich fuel that will result from the CO_2 removal operation. Additionally, there are unique issues with the gasification of higher moisture subbituminous and lignite coals that need to be solved before these energy resources can become IGCC feedstocks.

Under the current and near-term state of power generation technologies, the IGCC concept is attractive because the gasification technology suffers significantly less of an energy penalty than alternatives, such as pulverized coal boilers or gas turbine combined cycle power plants, if carbon capture was added. Whatever the technology, the addition of carbon management will increase costs of electricity, and while there may be niche markets for CO_2 in enhanced oil/gas recovery operations, the vast majority of CO_2 generated will be a waste product and will incur disposal costs.

5.5 Power Generation Systems with and without CO_2 Removal

The original and updated Parsons reports sponsored by the U.S. DOE and EPRI are the most detailed engineering comparisons in the public literature.[66] Exhibit 5-7 presents information from the study for IGCC and two PC units. The gasifier used in this study is

[66] Evaluation of Innovative Fossil fuel Power Plants with CO2 Removal, US DOE/NETL and EPRI, Prepared by ParsonsEnergy and Chemicals Group, December 2000 – updated 2002.

different from the GE-Energy (ex-Texaco) reactor used in the body of the report to calculate energy and material balances, but the relative comparison between systems with and without CO_2 removal would be consistent across types of gasifiers.

Exhibit 5-7, Carbon Management Comparison, U.S. DOE, EPRI, Parsons Study

Description	**IGCC - ConocoPhillips**		**Supercritical PC**		**Ultra Supercritical PC**	
Carbon Management	Capture	No Capture	Capture	No Capture	Capture	No Capture
Net Plant Size (MW)	404	425	329	462	367	506
CO_2 Capture Efficiency	91%	0%	90%	n/a	90%	n/a
Heat Rate (Btu/kWh) (HHV)	9,226	7,915	11,816	8,421	10,999	7,984
Efficiency (%,HHV)	37%	43%	29%	41%	31%	43%
Derating	14%		29%		27%	
Economic Criteria						
Cost-year basis	2000	2000	2000	2000	2000	2000
Capacity Factor	65%	65%	65%	65%	65%	65%
Fuel Cost ($/MMBtu) (HHV)	$1.24	$1.24	$1.24	$1.24	$1.24	$1.24
Book life (years)	20	20	20	20	20	20
Fixed Carrying Charge	13.80%	13.80%	13.80%	13.80%	13.80%	13.80%
Capital Costs ($/kW)						
Total Plant Cost	$1,642	$1,111	$1,981	$1,143	$1,943	$1,161
Total Plant Investment	$1,787	$1,209	$2,142	$1,235	$2,101	$1,256
Total Capital Requirement	$1,844	$1,251	$2,219	$1,281	$2,175	$1,301
Operation and Maintenance Costs						
Total O&M ($/kW-yr)	52.1	41	49.2	28.7	46.3	27.7
Fixed O&M ($/kW-yr)	33	27.5	33.3	20.2	30.8	19.1
Variable O&M (cents/kWh)	0.4	0.3	1.1	0.6	1.1	0.6
Fuel (cents/kWh)	1.1	1	1.5	1	1.4	1
Levelized Costs (cents/kWh)						
Capital	4.47	3.03	5.38	3.11	5.27	3.15
Total O&M	0.96	0.76	1.71	1	1.61	0.95
Fixed O&M	0.58	0.48	0.58	0.35	0.54	0.33
Variable O&M	0.38	0.28	1.13	0.64	1.07	0.62
Fuel	1.14	0.98	1.47	1.04	1.36	0.99
Total Cost of Electricity	6.58	4.77	8.56	5.15	8.24	5.1
COE increase for capture	1.8		3.41		3.14	
CO_2 Costs ($/ton)						
CO_2 Emission rate (t/MWh)	0.07	0.72	0.11	0.77	0.11	0.77

Description	IGCC - ConocoPhillips		Supercritical PC		Ultra Supercritical PC	
Cost of CO_2 Captured ($/ton)*	23.63	n/a	35.09	n/a	32.35	n/a
Cost of CO_2 Avoided ($/ton)*	27.98	n/a	51.22	n/a	47.22	n/a

* See Section 5.7 for differences between CO_2 avoided and captured costs.

Exhibit 5-8 presents similar literature data from the International Energy Agency (IEA) Greenhouse Gas program (circa 2003). Here the two cases are for Shell and GE-Energy gasifiers.

Exhibit 5-8, Gasification Carbon Management Data, IEA GHG 2003

Description	IGCC - Shell		IGCC - GE Energy	
Carbon Management	Capture	No Capture	Capture	No Capture
Net Plant Size (MW)	676	776	730	827
CO_2 Capture Efficiency	85%	0%	85%	0%
Heat Rate (Btu/kWh) (HHV)	9,890	7,916	10,832	8,979
Efficiency (%,HHV)	35%	43%	32%	38%
Derating	20%		17%	
Economic Criteria				
Cost-year basis	2002	2002	2002	2002
Capacity Factor	85%	85%	85%	85%
Fuel Cost ($/MMBtu) (HHV)	$1.50	$1.50	$1.50	$1.50
Book life (years)	25	25	25	25
Fixed Carrying Charge	11.00%	11.00%	11.00%	11.00%
Capital Costs ($/kW)				
Total Plant Cost	$1,744	$1,287	$1,402	$1,114
Total Plant Investment	$1,859	$1,371	$1,494	$1,187
Operation and Maintenance Costs				
Total O&M ($/kW-yr)	60.3	57.6	59.7	52.5
Fuel (cents/kWh)	1.6	1.3	1.7	1.4
Levelized Costs (cents/kWh)				
Capital	3.69	2.76	3.04	2.4
Total O&M	0.96	0.84	1	0.84
Fuel	1.59	1.27	1.72	1.42
Total Cost of Electricity	6.23	4.87	5.76	4.67
COE increase for capture	1.37		1.09	

Description	IGCC - Shell		IGCC - GE Energy	
CO_2 Costs ($/ton)				
CO_2 Emission rate (t/MWh)	0.14	0.76	0.15	0.83
Cost of CO_2 Captured ($/ton)	16.89	n/a	12.81	n/a
Cost of CO_2 Avoided ($/ton)	22	n/a	16.01	n/a

In Exhibit 5-8, the IEA data is not clear about which version of the GE-Energy gasifier (quench or heat recovery) was studied, or if there is an installed spare unit for this GHG case. Even without describing the details of the studies further, several important conclusions can be made from the data.

- The added cost for CO_2 removal is significant regardless of the technology. Examining the Total Plant Cost (TPC), which should be the most consistent value of the capital cost items because fewer add-on factors are applied as percents to the basic estimate, the delta IGCC cost ranges from about $300 (GE-Energy) to more than $500 (ConocoPhillips) per kW. The two pulverized coal plants increase about $800 per kW when CO_2 removal is added.

- Gasification cost and performance, when CO_2 removal is installed, are much more favorably compared to the PC cases. The improved economic performance results largely from the lower energy penalty incurred by IGCC than for PC when CO_2 removal is required.

- The difference in costs for systems with CO_2 removal is strongest when avoided costs are calculated; this is attributed to higher efficiency for gasification over pulverized coal units.

- The costs per ton of CO_2 sequestration remain high for all cases, and the range of estimates indicates a level of uncertainty that can only be reduced by the real-world construction of several plants.

- As with all developing technology comparisons, the technologies are changing – for PC plants new and improved amines are being researched; the U.S. DOE and others are moving forward with oxygen combustion research; gasification developers are investigating optimization of the processes for CO_2 removal possibly eliminating some operations to save costs and increase performance. Thus, the situation will require review as the technologies advance.

- Nearly all of the engineering assessments of power generation carbon management have used bituminous coals as the feedstock for PC and gasifier units. Investigators are starting to explore power and CO_2 removal systems fueled by subbituminous and lignite coals. Australia is expanding the knowledge base with work on high moisture brown coals.[67] Canada has also performed significant work with low rank coals, some of which is available in the literature. The available information is summarized below.

5.6 Coal Quality and CO_2 Removal

The Canadian Clean Power Coalition (CCPC) reported the results from the first phase of its work.[68] Exhibit 5-9 summarized the data for three types of coal being gasified and for a pulverized coal plant with CO_2 separation using amine absorption and stripping.

Exhibit 5-9, CCPC Summary Data for Plants with CO_2 Removal

Coal	Bituminous	Subbituminous	Lignite	Lignite
Technology	Gasification Plants			Pulverized Coal Plant
	GE-Energy Gasification	GE-Energy Gasification	Shell Gasification	Amine Absorption
Net power (MW)	444.5	436.8	361.1	310.9
Efficiency, % (LHV)	32.97	27.71	30	31.8
Efficiency, % (HHV)[1]	30	25	26	27
CO_2 captured (%)	87	92	85.7	95
CO_2 emitted, g/kWh	130	102	182	60
Capital cost (U.S. $/kW)	1,917	2,190	2,828	2,824
COE (U.S. cents/kWh)	6.84	6.21	8.39	7.43

Note 1. HHV efficiencies estimated; LHV results stated in the report.

The U.S. and IEA efficiency and cost results compare fairly closely for bituminous coals. The new data from the Canadian work is the relative comparison of the three coals. Some of the conclusions which can be made from this data include:

- The efficiency difference between systems using bituminous and subbituminous/lignite coals is significant (about 5%). The lignite coal efficiency is greater than that of subbituminous coal because the Shell gasifier is a dry feed unit. It is not clear that all the impacts of the Shell versus GE-Energy units were considered. In the report, ChevronTexaco, who owned the gasifier technology at that time, did not believe that its gasifier could be practically used with lignite.

[67] Victorian Government's Greenhouse Challenge for Energy, CRC for Clean Power from Lignite, August 2003.
[68] Summary of Canadian Clean Power Coalition Work on CO2 Capture and Storage, by Geoffrey F Morrison, August 2004.

- The capital cost difference is notably higher for the lignite gasification case than for both of the other coals.

- The costs for the lignite PC plant with amine CO_2 removal could be compared to the capital cost for the supercritical plant in the Parsons report as an indication of coal rank impacts on PC plants with CO_2 removal. The Parsons capital cost is $2,219 compared to $2,824 per kW for the Canadian lignite PC case. Aside from more specific differences that could exist between the studies, most of the cost difference is assumed to be caused by a larger boiler required to fire the low heating value lignite.

- The difference in efficiencies between the Parsons supercritical plant and the CCPC lignite plant is only about 2%. Much of the difference can likely be accounted for by the heat needed to evaporate the extra lignite moisture.

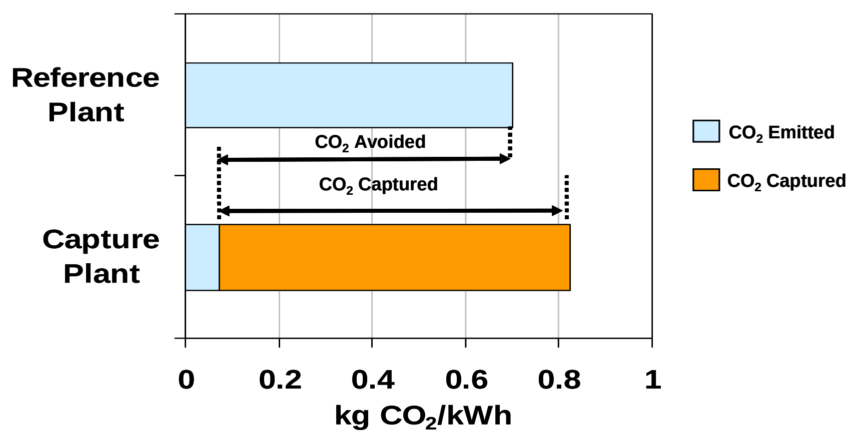
5.7 Note on Avoided Costs

The cost of an environmental control system can be discussed in terms of either the cost per ton of pollutant removed or the cost per ton "avoided." For a CO_2 removal system like amine scrubbers there is a big difference between the cost per ton CO_2 removed and the cost per ton CO_2 avoided. All avoided cost calculations require a "reference plant" without the removal system for a comparison to be made on unit cost avoided basis (see Exhibit 5-10 below). Avoided cost can be calculated as follows:

$$\$/tonneAvoided = \frac{COE_{Capture} - COE_{Reference}}{CO_2Emissions_{Reference} - CO_2Emissions_{Capture}}$$

Note: Cost of electricity (COE) in mills/kWh and CO_2 Emissions in kg/kWh

Exhibit 5-10, Illustration of Avoided Cost for CO_2 Capture



Some other references perform the calculation by adding lost capacity from a specified generation source such as a new gas turbine combined cycle plant with emissions of its own used in the calculation.

5.8 CO_2 Pipeline Transport

Pipeline transportation of CO_2 is a commercial operation in North America with more than 350 million standard cubic feet being moved significant distances, mainly for enhanced oil recovery operations.

CO_2 separation processes applied to a fossil fuel-fired power plant result in additional energy consumption and the direct reduction of power output. Starting with atmospheric pressure and a desired pipeline pressure of 1,600 psia, the energy requirement for CO_2 liquefaction by inter-cooled 5-stage compression is about 0.05 kWh/lb of CO_2. For 90% CO_2 removal, the CO_2 liquefaction reduces the efficiency of coal-fired power plants by about 3 to 5 percentage points. Estimates of pipeline diameter and CO_2 flow rates are shown in Exhibit 5-11.[69]

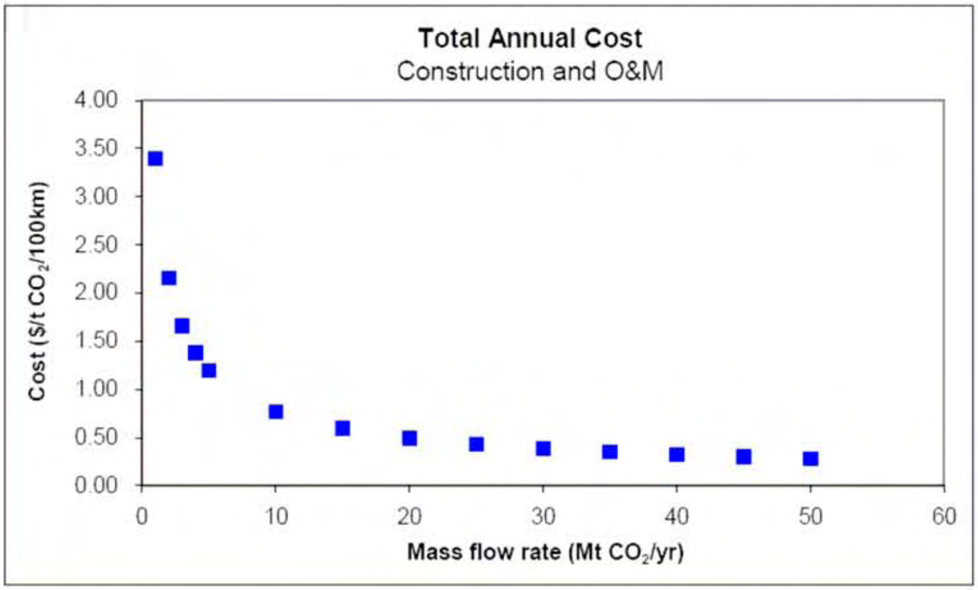
Exhibit 5-11 Pipeline Size and CO_2 Flows

Diameter, inches	Range of Flow Rate, millions of tons per year
12	1 to 3
16	3 to 7
20	7 to 12
24	12 to 19
28	19 to 28
32	28 to 40

An approximate straight-line cost for pipeline construction is $15,000 per inch-mile. Annual O&M costs are about $1,500 per mile independent of pipe diameter. The costs are strongly dependent on site and route specific features. However, transportation costs are typically viewed as relatively minor components of the overall cost for carbon management. Exhibit 5-12 shows CO_2 transportation cost estimates from a source, ranging from $0.50 to $2 per metric ton for a distance of 100 km, or about 220 miles.[70]

[69] Evaluation of Innovative Fossil fuel Power Plants with CO2 Removal, US DOE/NETL and EPRI, Prepared by ParsonsEnergy and Chemicals Group, December 2000 – updated 2002.
[70] The Economics of CO2 Storage, Gemma Heddle, Howard Herzog & Michael Klett, MIT. August 2003.

Exhibit 5-12, CO_2 Transportation Cost Data



5.9 Geological Sequestration

Carbon sequestration is the removal and retention of carbon dioxide (CO_2) in terrestrial, oceanic, and geologic environments. Geologic sequestration – also known as carbon capture and storage (CCS) – is the underground emplacement of anthropogenic CO_2 captured from industrial facilities, such as power plants and cement manufacturing facilities. Instead of releasing the captured CO_2 to the atmosphere, CCS operations will compress the gas to a "supercritical" liquid and send it via a pipeline to an injection well, where it is pumped underground to depths generally greater than 800 meters to maintain critical pressures and temperatures. Once underground, the CO_2 occupies pore spaces in the surrounding rock. Candidate sites for geologic storage include deep saline formations, depleted oil and gas reserves, and unminable coal beds. Suitable sites have a caprock, or an overlying impermeable layer, that prevents CO_2 from escaping back towards the surface.

There appear to be no major technical hurdles to implementing geologic sequestration in the U.S. The various technologies required to implement a CCS project exist today and several are used in the field routinely by the oil and gas and waste disposal industries. Although there may be risks associated with large-scale injection and potential leaks of CO_2, it is anticipated that they can be avoided with proper siting, operation and maintenance, and long-term monitoring. Capture costs and concerns with long-term liability for storage sites are major considerations still being addressed by ongoing R&D. In addition to technical and economic hurdles to commercial deployment, public awareness and acceptance of projects to store very large volumes of CO_2 will need to be greatly increased. Also, while there is experience with regulations and permits for smaller amounts of materials, i.e. hazardous waste and waste injection wells, there is no set of regulations for CO_2 storage, and in addition to environmental issues, questions remain about ownership and liability for the CO_2 and for ownership of the storage pore space.

In the U.S., large point sources of CO_2 (each emitting more than 100,000 tons of CO_2 per year) originate from various industrial sectors including coal-fired power plants, ammonia production, and cement manufacture among others. There are approximately 1,700 of these sources in the U.S. that collectively emit more than 3 gigatons of CO_2 (GtCO2) per year.[71] Initial assessments show there is an abundance of geologic storage capacity, well distributed throughout the U.S. Although capacity estimates vary, recent studies from Battelle estimate storage capacity of more than 3,900 GtCO2

5.9.1 Potential Storage Formations

The geological formations of primary interest to sequestration include:

- Existing oil and gas fields and potential enhanced oil/gas recovery (EOR) conditions
- Depleted oil and gas fields
- Deep saline formations
- Deep unminable coal seams, possibly with coal bed methane recovery

Other possibilities include storage in mafic/basalt rock formations and above ground conversion of CO_2 to solid carbonate materials. These are much less mature options than the four bulleted items. The MIT reference noted previously contains details about the technologies and costs for various sequestration options.

Existing oil and gas fields and enhanced oil/gas recovery (EOR)

Enhanced recovery with CO_2 floods is used commercially in North America. There were some 70 CO_2 floods in the United States in 2000 that resulted in almost 200,000 bbl of oil per day, which is equivalent to 5 percent of total U.S. oil production during the same period. Most of these CO_2 floods are located in the southwestern United States within the Permian basin of western Texas and eastern New Mexico. The majority of the CO_2 for EOR operations comes from natural sources, because CO2 captured from most anthropogenic sources is currently too expensive to compete with the naturally occurring (produced) CO_2.

EOR and CO_2 sequestration are being studied extensively for the first time in an international project at the Weyburn field, Saskatchewan Canada. The CO_2 source is the Dakota Gasification plant near Great Plains North Dakota. The Weyburn EOR project will not conclude with the conventional "blowdown" which may release CO_2 back to the atmosphere. Instead the operators will maintain the site in order to test and monitor long-term sequestration. Sequestration as part of an EOR operation has the attraction of being a revenue producing process, and is very likely to be some of the first sequestration

[71] "Carbon Dioxide Capture and Geological Storage," Report by JJ Dooley, et al., April 2006, GTSP Website http://www.pnl.gov/gtsp/news/, accessed June 5, 2006

opportunities to be implemented at large scale. For example, the British Petroleum (BP) Carson Hydrogen Power project will convert the carbon in petroleum coke, a by-product of the refining process, and recycled waste water into hydrogen, a clean-burning gas, and CO_2. The hydrogen gas will be used to fuel a power station capable of providing the California power grid with 500 MW of electricity. At the same time, about 4 million tonnes of CO_2 per year will be captured, transported and stored in deep underground oil reservoirs where it will enhance existing oil production.

If EOR projects are to include a CO2 sequestration component, changes may be needed to the facility and/or operations. For example, different project goals may necessitate additional site characterization, the use of multiple geologic formations, or temporary CO2 storage. A critical component will be monitoring and verifying the volume of CO2 stored and additional site closure practices to ensure CO2 is sequestered for the long time frames required.

Depleted oil and gas fields

Injection of CO_2 into depleted oil and gas fields would be similar to commercial EOR experience. While one of the main attractions for using the fields is that large amounts of geological data will be available, the existing fields will also have numerous old wells that may no longer be sealed and could leak the CO_2 back to the atmosphere. Before sequestration, the existing field would have to be closely examined and issues such as concerns regarding old wells would have to be addressed.

Deep saline formations

Sequestration in deep saline deposits has the potential to geologically store the most CO_2. Along with the Weyburn field tests, the only other commercial-scale projects dedicated to geologic CO_2 storage are at the Sleipner West field in the North Sea and the In Salah gas field in Algeria. Sleipner West is a natural gas/condensate field operated by Statoil and is located about 500 miles off the coast of Norway. The natural gas has a CO_2 content of about 9 percent which, to meet commercial specifications, must be reduced to 2.5 percent. At Sleipner, the CO_2 is compressed and injected via a single well into the Utsira Formation, a 500 foot thick, brine saturated formation located at a depth of about 2,000 feet below the seabed. The operation is commercially driven by a carbon tax imposed by Norway.

In 2004, BP launched a CO2 capture and storage project at the In Salah gas field, in the Algeria desert. In Salah is a joint venture between Sonatrach, the Algeria national energy company, BP and Statoil. Approximately 10% of the gas in the reservoir is made up of CO_2. Rather than venting the CO_2, which is the established practice on other projects of this type, the project is compressing it and injecting it in wells 1,800 meters deep into a lower level of the gas reservoir where the reservoir is filled with water. Around one million tonnes of CO_2 will be injected into the reservoir every year.

The most important trapping mechanism to contain CO_2 in deep saline reservoirs is hydrodynamic trapping, where a caprock prevents upward movement of CO_2. Saline and other types of reservoirs also have two additional trapping mechanisms that help contain the CO_2 : solubility and mineral trapping. Solubility trapping is the dissolution of CO_2 into the reservoir fluids; mineral trapping is the reaction of CO_2 with minerals in the host formation to form carbonates. As the CO_2 moves through the deposit, it comes into contact with uncarbonated formation water and reactive minerals. A portion of the CO_2 dissolves in the formation water and becomes permanently fixed by reactions with minerals in the host rock. Over long periods of time, the CO_2 might all dissolve and be fixed by mineral reactions, essentially becoming permanently sequestered.

DOE and others are testing sequestration in deep saline deposits in the U.S. First round of tests are completed in the Frio formation, a deep saline deposit in Texas. A discussion of DOE's Regional Sequestration Partnership and summary of proposed projects follows in Section 5.10.

Deep unminable coal seams, possibly with coal bed methane recovery

Sequestration into deep coal seams has been proposed as a means to safely store CO_2 because the CO_2 will both react with the coal materials, and displace methane from the coal. Some tests have been performed for the purpose of enhancing coal-bed methane recovery, but little has been done to examine the sequestration issues. As with the other EOR technologies there is the potential benefit of increased energy production that could pay for some or all of the CO_2 sequestration costs.

5.10 CO_2 Sequestration Regional Partnerships

A very important effort to advance the technical knowledge and acceptance of sequestration is the U.S. DOE program of Regional Sequestration Partnerships. The seven partnerships include 40 States and 4 Canadian Provinces. More than 200 industry and government organizations are participating with the primary contractors. The major results and data from Phase I can be found at the NETL/DOE website.[72] These results will be used to deploy a geographic information system (GIS) database that will be available to partnership members and the public. DOE will use the regional data to develop a National/North American sequestration GIS.

As part of the regional effort to date, the partnerships examined CO_2 separation and capture technologies and have, to varying degrees, compared and matched technologies with the sources of CO_2 and the potential sequestration sites. The objective of this work was to estimate cost curves for carbon management within the region.

The same regional partnerships have been awarded contracts for a second phase of work. In Phase II, data collection, public awareness and regulatory assessment will continue, and fieldwork will inject small amounts of CO_2 into selected geological formations. Tests of terrestrial sequestration in the different regions will also be conducted.

[72] NETL/DOE Website, www.netl.doe.gov/technologies/carbon_seq/partnerships/partnerships.html, accessed on May 30, 2006

As noted at the beginning of this report, challenges associated with geological sequestration could be the main obstacle to power generation carbon management. The DOE roadmap for sequestration includes one large scale sequestration project by 2009, but it is not clear how this demonstration would be coordinated with the regional partnerships' second phase, which also runs to about 2009 and DOE's FutureGen concept, which aims for completion by 2012. Such demonstrations will help reduce technical uncertainties, especially with regard to potential health, safety, and environmental impacts of commercial activities.

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Appendix A covers the capital and operating cost estimates for IGCC and PC power plants. The costs are derived from recent published documents and Nexant experience with similar projects. The estimates specifically prepared for the plant configurations selected for this study are in the 4th Quarter 2004 dollars.

As noted previously, this study is a snapshot in time and costs as well as performance are evolving and changing as experience increases and because of more basic changes in the economy such as price changes (steel and energy are prime examples). The study costs are conceptually estimated for an Nth plant, i.e. one of many commercial facilities and not for demonstration or the first of a kind plants needed to obtain commercial viability. The Nth plant criteria are truer for PC plants than for IGCC plants because of the numbers built for each technology. There are also costs that can not be fully estimated such as site differences, warrantees/guarantees or fees for systems treating fuels or other conditions that are outside of the suppliers' experiences.

The uncertainty of cost estimates sometimes results in values presented as ranges, or with uncertainties assigned for all or parts of the estimates. The engineering level of this study did not employ this approach, but the study reader should be aware that the costs will vary for a number of reasons at the time of the "snapshot", and will also vary with time as the knowledge base expands.

Summary

Cost data presented in this appendix are drawn from a number of sources. Where appropriate, the data has been updated by escalation to the end of 2004 price and wage level, and adjusted to a consistent 500 MW net plant size. The costs are consistent with the plant performance estimates presented in the body of the report. However, it should be noted that site and design specific criteria can cause a significant range of costs that could only be refined with much more detailed engineering, including budgetary quotes and engineering packages from major technology suppliers.

Exhibits A-1 and A-2 summarize the cost estimates developed for the PC and IGCC plant configurations used in this study. The methodologies and sources for these estimates are discussed further in this appendix. While data is from several sources, the values have been adjusted as noted above and consistent factored cost elements such as engineering services, contingency and other owner's costs are used to calculate the cost categories in the exhibits.

Exhibit A-1, Total Capital Requirement and Operating Cost

Power Plants	Bituminous Coal	Subbituminous Coal	Lignite Coal
Subcritical PC			
Total Capital Requirement $/kW	1,347	1,387	1,424
Annual Operating Cost, 1,000s	27,700	28,300	29,640
Supercritical PC			
Total Capital Requirement $/kW	1,431	1,473	1,511
Annual Operating Cost, 1,000s	29,000	29,600	30,940
Ultra Supercritical PC			
Total Capital Requirement $/ kW	1,529	1,575	1,617
Annual Operating Cost, 1,000s	30,400	31,100	32,440
GE Energy IGCC			
Total Capital Requirement $/ kW	1,670	1,910	Not Applicable*
Annual Operating Cost, 1,000s	27,310	29,700	Not Applicable*
Shell IGCC			
Total Capital Requirement $/ kW	1,840	2,100	2,350
Annual Operating Cost, 1,000s	Not Reported	Not Reported	34,000

* The GE Energy gasification technology is not used with lignite.

Exhibit A-2 Summary of Costs

Power Plants	Total Plant Cost $/ kW	Total Plant Investment $/kW	Total Capital Requirement $/ kW	Operating Cost $1,000s
Subcritical PC				
Bituminous Coal	1,187	1,303	1,347	27,700
Subbituminous Coal	1,223	1,343	1,387	28,300
Lignite	1,255	1,378	1,424	29,640
Supercritical PC				
Bituminous Coal	1,261	1,384	1,431	29,000
Subbituminous Coal	1,299	1,426	1,473	29,600
Lignite	1,333	1,463	1,511	30,940
Ultra Supercritical PC				
Bituminous Coal	1,355	1,482	1,529	30,400

Power Plants	Total Plant Cost $/ kW	Total Plant Investment $/kW	Total Capital Requirement $/ kW	Operating Cost $1,000s
Subbituminous Coal	1,395	1,526	1,575	31,100
Lignite	1,432	1,566	1,617	32,440
GE Energy IGCC				
Bituminous Coal	1,430	1,610	1,670	27,310
Subbituminous Coal	1,630	1,840	1,910	29,700
Lignite*	Not Applicable	Not Applicable	Not Applicable	Not Applicable
Shell IGCC				
Bituminous Coal	1,570	1,770	1,840	Not Reported
Subbituminous Coal	1,790	2,020	2,100	Not Reported
Lignite	2,000	2,260	2,350	34,000

* The GE Energy gasification technology is not used with lignite.

Pulverized Coal Plant Cost Estimates

Capital Costs

Exhibits A-3, 4, and 5 present cost estimates for the pulverized coal plants with a capacity of 500 MW net. Exhibit A-3 show subcritical units with three study coal types – high-sulfur bituminous, low-sulfur subbituminous, and lignite. A breakdown of costs is shown for the first coal as an example of how costs are distributed among the major plant sections. Cost breakdowns would be similar for the other coals.

Exhibits A-4 and 5 show the estimates for supercritical and ultra-supercritical units and the three coals. An allowance for uncertainty (contingency) of 20% is used for the ultra-supercritical plant as an estimate of its less mature technology development. The allowance is 15% for other plants. Other cost factors used in the PC capital cost estimates are as follows:

- Engineering Services, 8% of Total Constructed Cost (TCC)
- Interest During Construction, 12% of TCC
- Startup, 2.5% of TCC
- Spare Parts, Working Capital, & Land, 2% of TCC
- Escalation to 2004 as required using 2% per year cost escalation

Exhibit A-6 presents a comparison of costs found in the literature for PC plants. While not exactly the same in all critical aspects, these plants are consistent and show the relatively small variance in costs from subcritical to ultra-supercritical. The differences in costs from the steam generator choice could easily be overshadowed by site conditions or owner preferences among the plants.

There is only a limited amount of cost information available in the industry for comparison of the PC plants fired by the three coals. The Canadian Clean Power Coalition (CCPC) published an executive summary of work with some information that is reported below.

Capital costs for supercritical plants in Canadian dollars (not reported, but the year is about 2002) and the associated heat rates are as follows:

• 300 MW lignite plant	$915 million	9,400 Btu/kWh
• 400 MW subbituminous plant	$1005 million	8,900 Btu/kWh
• 300 MW bituminous plant	$866 million	8,900 Btu/kWh

The above capital costs in $/kW, using 1.56 Canadian to U.S. dollars, are as follows:

• 300 MW lignite plant	$ 1,955
• 400 MW subbituminous plant	$ 1,610
• 300 MW bituminous plant	$ 1,850

There is a question of why the bituminous coal-fired plant is more expensive than the subbituminous plant. The CCPC has been contacted and asked if the reported values are correct, and the reason for the seemingly out-of-sequence cost comparison. The 500 MW bituminous supercritical plant cost developed for the EPA study is about $1,430 /kW. This is a significant difference with the DOE and EPRI costs, even considering Canadian conditions and economies of scale. The CCPC considers its work proprietary, and could not provide details that might explain the differences. The Canadian work, while noted, is not used in the current study.

An EPRI paper presented at the Gasification Technologies Conference, 2004, "Pulverized Coal and IGCC Plant Cost and Performance Estimates, George Booras and Neville Holt showed a graphic relationship between coal quality, cost and performance of PC plants and IGCC plants. The figure is repeated here as Exhibit A-7.

Exhibit A-3 Subcritical Pulverized Coal Estimates, 1,000s
2004 Price and Wage Level

500 MW Net	High-Sulfur Bituminous Coal				Subbitu-minous Coal	Lignite
Subcritical Pulverized Coal Plant	Equipment	Materials	Installation	Total Installed Cost	Total Installed Cost	Total Installed Cost
PC Boiler and Accessories	67,200	-	29,400	96,600	99,500	102,100
Flue Gas Cleanup	45,600	-	26,700	72,300	74,500	76,500
Ducting and Stack	13,100	400	10,400	23,900	24,600	25,300
Steam T-G Plant, including Cooling Water System	67,100	5,800	26,800	99,700	102,700	105,300
Accessory Electric Plant	12,200	3,800	11,100	27,100	27,900	28,700
Balance of Plant	61,200	25,200	76,700	163,100	168,000	172,400
Subtotal, Total Constructed Cost	266,400	35,200	181,100	482,700	497,200	510,300
Engineering Services, 8% of TCC				38,600	39,800	40,800
Allowance For Uncertainty, 15% of TCC				72,400	74,600	76,500
Total Plant Cost				593,700	611,600	627,600
Total Plant Cost - $ per Kilowatt				1,187	1,223	1,255
Interest During Construction (IDC), 12% of TCC				57,900	59,700	61,200
Total Plant Investment				651,600	671,300	688,800
Prepaid Royalties				0	0	0
Initial Catalyst and Chemicals				100	100	100
Startup, 2.5% of TCC				12,100	12,400	12,800
Spare Parts, Working Capital, & Land, 2% of TCC				9,700	9,900	10,200
Total Capital Investment				673,500	693,700	711,900
Total Capital Cost - $ per Kilowatt				1,347	1,387	1,424

Exhibit A-4 Supercritical Pulverized Coal Estimates, 1,000s
2004 Price and Wage Level

500 MW Net	High-Sulfur Bituminous Coal	Subbituminous Coal	Lignite
Supercritical Pulverized Coal Plant	Total Installed Cost	Total Installed Cost	Total Installed Cost
PC Boiler and Accessories	129,400	133,300	136,700
Flue Gas Cleanup	72,600	74,800	76,700
Ducting and Stack	24,300	25,000	25,700
Steam T-G Plant, including Cooling Water System	109,200	112,500	115,400
Accessory Electric Plant	28,600	29,400	30,200
Balance of Plant	148,600	153,000	157,000
Subtotal, Total Constructed Cost	512,700	528,000	541,700
Engineering Services, 8% of TCC	41,000	42,200	43,300
Allowance For Uncertainty, 15% of TCC	76,900	79,200	81,300
Total Plant Cost	630,600	649,400	666,300
Total Plant Cost - $ per Kilowatt	1,261	1,299	1,333
Interest During Construction (IDC), 12% of TCC	61,500	63,400	65,000
Total Plant Investment	692,100	712,800	731,300
Prepaid Royalties	0	0	0
Initial Catalyst and Chemicals	100	100	100
Startup, 2.5% of TCC	12,800	13,200	13,500
Spare Parts, Working Capital, & Land, 2% of TCC	10,300	10,600	10,800
Total Capital Investment	715,300	736,700	755,700
Total Capital Cost - $ per Kilowatt	1,431	1,473	1,511

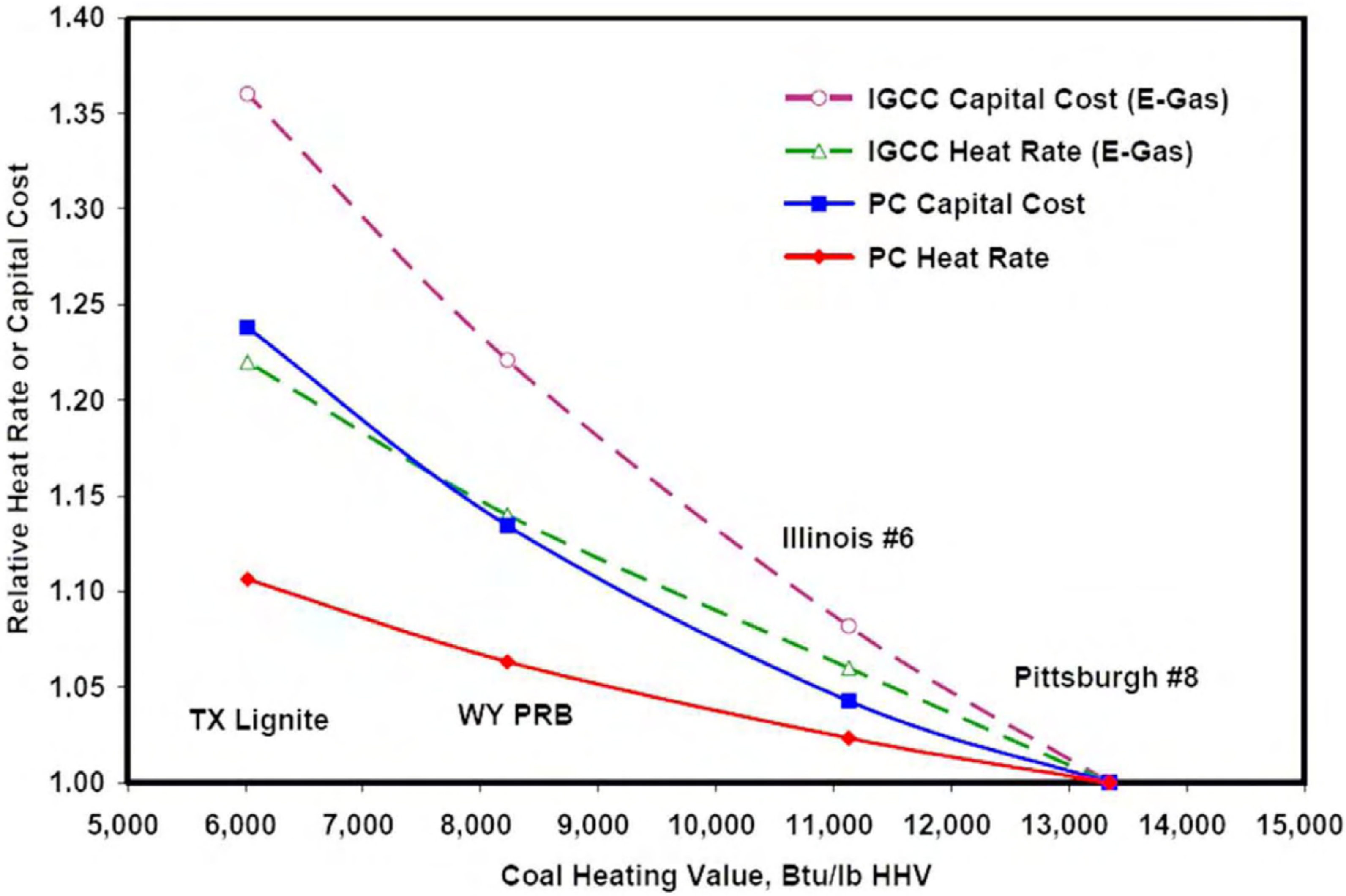
Exhibit A-5 Ultra Supercritical Pulverized Coal Estimates, 1,000s
2004 Price and Wage Level

500 MW Net	High-Sulfur Bituminous Coal	Subbituminous Coal	Lignite
Ultra Supercritical Pulverized Coal Plant	Total Installed Cost	Total Installed Cost	Total Installed Cost
PC Boiler and Accessories	138,200	142,300	146,000
Flue Gas Cleanup	67,500	69,500	71,400
Ducting and Stack	23,100	23,800	24,400
Steam T-G Plant, including Cooling Water System	130,800	134,700	138,200
Accessory Electric Plant	27,200	28,000	28,800
Balance of Plant	142,400	146,700	150,500
Subtotal, Total Constructed Cost	529,200	545,000	559,300
Engineering Services, 8% of TCC	42,300	43,600	44,700
Allowance For Uncertainty, 20% of TCC	105,800	109,000	111,900
Total Plant Cost	677,300	697,600	715,900
Total Plant Cost - $ per Kilowatt	1,355	1,395	1,432
Interest During Construction (IDC), 12% of TCC	63,500	65,400	67,100
Total Plant Investment	740,800	763,000	783,000
Prepaid Royalties	0	0	0
Initial Catalyst and Chemicals	100	100	100
Startup, 2.5% of TCC	13,200	13,600	14,000
Spare Parts, Working Capital, & Land, 2% of TCC	10,600	10,900	11,200
Total Capital Investment	764,700	787,600	808,300
Total Capital Cost - $ per Kilowatt	1,529	1,575	1,617

Exhibit A-6, Comparison of Cost Estimates from Published Sources

	Net Capacity, MW	Cost Year	Coal	SO_2 Control	NO_X Control	Particulate	Heat Rate Btu/kWh % Efficiency, HHV	Total Plant Cost, $/kW
Market Based Advanced Coal Power Systems Final Report, May 1999 U.S. DOE/FE-0400								
Subcritical PC	400	1998	Illinois #6	WL-FGD	Low NO_X Burners	ESP	9,077 37.6%	1,129
Supercritical PC	400	1998	Illinois #6	WL-FGD	Low NO_X Burners, SCR	Fabric Filter	8,568 39.9%	1,173
Ultra Supercritical PC	400	1998	Illinois #6	WL-FGD	Low NO_X Burners, SNCR	Fabric Filter	8,251 41.4	1,170
Evaluation of Innovative Fossil Fuel Power Plants with CO_2 Removal, EPRI, U.S. DOE/NETL 1000316 December 2000								
Supercritical PC	462	Dec-99	Illinois #6	WL-FGD	Low NO_X Burners, SCR	Fabric Filter	8,421 40.5%	1,143
Ultra Supercritical PC	506	Dec-99	Illinois #6	WL-FGD	Low NO_X Burners, SCR	Fabric Filter	7,984 42.7%	1,161
Pulverized Coal and IGCC Plant Cost and Performance Estimates, George Booras EPRI October 2004								
Subcritical PC	500	2003	Illinois #6	WL-FGD	Low NO_X Burners, SCR	Fabric Filter	9,560	1,290
Subcritical PC	500	2003	Pittsburgh #8	WL-FGD	Low NO_X Burners, SCR	Fabric Filter	9,310	1,230
Supercritical PC	500	2003	Illinois #6	WL-FGD	Low NO_X Burners, SCR	Fabric Filter	8,920	1,340
Supercritical PC	500	2003	Pittsburgh #8	WL-FGD	Low NO_X Burners, SCR	Fabric Filter	8,690	1,290

Exhibit A-7, Comparison of Coal Quality, Cost and Performance



Operating and Maintenance Costs

Operating costs from the DOE/NETL and EPRI report were reviewed and updated for the study. The costs are presented in Exhibit A-8.

Exhibit A-8, Annual Operating and Maintenance Costs, $1000s

Nominal 500 MW PC Plants	High Sulfur Bituminous Coal	Subbituminous Coal	Lignite
Subcritical Pulverized Coal			
Operating Labor	5,300	5,300	5,830
Maintenance	6,800	7,000	7,200
Administrative & Support Labor	2,100	2,100	2,310
Consumables	13,500	13,900	14,300
TOTAL	27,700	28,300	29,640
Supercritical Pulverized Coal			
Operating Labor	5,300	5,300	5,830
Maintenance	7,300	7,500	7,700
Administrative & Support Labor	2,100	2,100	2,310
Consumables	14,300	14,700	15,100
TOTAL	29,000	29,600	30,940
Ultra Supercritical Pulverized Coal			
Operating Labor	5,300	5,300	5,830
Maintenance	8,000	8,200	8,500
Administrative & Support Labor	2,100	2,100	2,310
Consumables	15,000	15,500	15,800
TOTAL	30,400	31,100	32,440

Fuel Costs and Credits for Byproducts are excluded.

As shown by the table, there is not a significant difference in O&M caused by coal type, or the PC technology. Operating and support labor is judged to be the same for the bituminous and subbituminous plants and somewhat more for lignite; Maintenance costs increase as the cost for the plants increase, as does consumables. The consumables include water, chemicals, miscellaneous consumables, and wastes disposal.

While not shown on the table because it is plant and location dependent, the fuel costs for the different coals would be a much larger delta of O&M costs. Typical costs and ranges for the three coals are shown on Exhibit A-9. Illinois and Ohio represent the high sulfur bituminous coal, North Dakota and Texas represent lignite and Wyoming is the subbituminous coal. (There is no explanation for the delivered Illinois price being lower than the mine cost.)

Exhibit A-8, 2004 Coal Price Data
EIA Coal Price Data 2004; cost per million Btus calculated

	$/ton	$/ton Delivered	$/MMBtu	$/MMBtu Delivered	Study Coals MMBtu/lb
Illinois	25.72	22.05	$ 1.10	$ 0.94	11,667
Ohio	23.82	31.99	$ 1.02	$ 1.37	11,667
North Dakota	9.67	10.20	$ 0.77	$ 0.81	6,312
Texas	15.39	21.82	$ 1.22	$ 1.73	6,312
Wyoming	7.12	15.28	$ 0.40	$ 0.87	8,800

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Integrated Gasification Combined Cycle Cost Estimates

Background

One of the first things to be noted is that costs vary among the alternative gasification and IGCC systems. The variations in cost are illustrated in later tables. For the present study, the summary results are limited to 500 MW net generation IGCC plants and three coals. For the bituminous and subbituminous coals a GE Energy (Ex-ChervonTexaco, Texaco) gasifier with coal-water slurry feed system is used. The unit includes radiant and convective heat recovery for higher efficient operations and uses two-50% gasification trains. For the high moisture lignite coal, a solid feed Shell gasifier is selected with two-50% gasification trains.

The estimated costs are summarized in Exhibit A-9. Costs are presented for Shell and the two other coals in addition to the lignite based plant. The costs are for the end of 2004 price and wage levels and 500 MW net IGCC plants. The costs are for plants with two 50% gasification trains, but do not have a spare gasifier.

Exhibit A-9, Summary of IGCC Cost Estimates

IGCC Plants	Bituminous Coal	Subbituminous Coal	Lignite Coal
GE Energy IGCC			
Total Plant Cost $/kW	1,430	1,630	Not Applicable
Total Plant Investment	1,610	1,840	Not Applicable
Total Capital Requirement $/kW	1,670	1,910	Not Applicable
Operating Cost	27,310	29,700	Not Applicable
Shell IGCC			
Total Plant Cost $/kW	1,570	1,790	2,000
Total Plant Investment	1,770	2,020	2,260
Total Capital Requirement $/kW	1,840	2,100	2,350
Operating Cost	Not Reported	Not Reported	34,000

While the ConocoPhillips technology has fewer operating installations than the GE Energy gasifier, estimates for the ConocoPhillips unit are consistently about $100 per kW less. This is relatively small in comparison to the total costs, and the cost values could change as site and coal specific designs are prepared for either or both technologies.

Cost Data

Two cost estimate tables are presented in Exhibits A-10 and 11. The exhibits show breakdowns of costs for the selected IGCC data. A later exhibit contains data from a number of recent publications, and is presented to compare costs across the data set for types of gasifiers with different types of coals.

Exhibit A-10, GE Energy (Ex-Texaco) IGCC Costs, $1,000s

Texaco Gasifier IGCC Base Case Escalated to 2004; Adjusted to 500 MW nominal size	Single Train Quench Gasifier	$/kW	Single Train Radiant + Convective Gasifier	$/kW
Coal Slurry Preparation	38,100	76	37,500	70
Oxygen Plant	73,800	148	74,000	137
Gasifier SINGLE UNIT	45,300	91	108,700	202
Soot Blower Recycle Compression	Na	na	4,800	9
Gas Cooling Saturation	24,100	48	14,500	27
MDEA	7,400	15	7,700	14
Claus	14,000	28	13,900	26
SCOT	5,900	12	5,900	11
Gas Turbine System	74,400	149	74,400	138
HRSG Steam Turbine	62,500	125	69,900	130
\Water Systems	24,400	49	29,200	54
Civil	31,800	64	37,900	70
Piping	24,400	49	29,200	54
Controls	8,900	18	10,700	20
Electrical	27,600	55	32,900	61
INSTALLED COST (IC)	462,600	925	551,200	1,023
Engineering, 8% of IC	37,000	74	44,100	82
Process Contingency, 5% of IC	23,100	46	27,600	51
Project Contingency, 15% of IC	69,400	139	82,700	153
TOTAL PLANT COST (TPC)	592,100	1,184	705,600	1,309
Total Plant Cost $/kW		1,184		1,309
Interest During Construction (IDC)	55,500	111	66,100	123
TOTAL PLANT INVESTMENT	647,600	1,295	771,700	1,432
Prepaid Royalties	2,310	5	2,760	5
Initial Catalyst and Chemicals	230	0	280	1
Startup	11,570	23	13,780	26
Spare Parts, Working Capital and Land	9,250	19	11,020	20
TOTAL CAPITAL REQUIREMENT	670,960	1,342	799,540	1,483
Total Capital Requirement $/kW	1,342		1,483	
Illinois #6 coal; Single train of gasification; W501 G turbine; cold gas cleaning (MDEA, CLAUS, SCOTT to elemental sulfur)				

Exhibit A-10 data is from the DOE/NETL report "Texaco Gasifier IGCC Base Cases", PED-IGCC-98-001 latest revision June 2000. It is important to note that the costs are for a single train of gasification. Using two trains (50% each) or using two 50% trains plus a spare gasifier could increase costs by $150 to $200 per kW. The costs have been escalated to end of 2004 price levels and adjusted to 500 MW net plant size. Also, the cost items below the Installed Cost total have been adjusted to be consistent across the study plants. The plant with radiant and convective heat recovery generates more electricity and is more efficient, but is also more costly.

Exhibit A-11 shows similar (not as many breakdowns) data for the ConocoPhillips gasifier (Ex-EGas, Global Energy gasifier).

Exhibit A-11, ConocoPhillips (Ex-EGas) IGCC Costs, $1,000s

ConocoPhillips Gasifier Escalated to 2004; Adjusted to 500 MW nominal size	2 – 50% Gasifier Trains with H-Type Turbine	$/kW
Gasifier, ASU & Accessories	206,700	413
Gas Cleanup & Piping	42,400	85
Combustion Turbine and Accessories	77,200	154
HRSG, Ducting and Stack	25,800	52
Steam T-G Plant, including Cooling Water System	45,700	91
Accessory Electric Plant	28,800	58
Balance of Plant	106,500	213
INSTALLED COST	533,100	1,066
Engineering Services and Fee, 8%	533,100	1,066
Process Contingency, 5%	42,600	85
Project Contingency, 15%	26,700	53
TOTAL PLANT COST (TPC)	80,000	160
Total Plant Cost $/kW	682,400	1,365
Interest During Construction (IDC)	1,365	
TOTAL PLANT INVESTMENT	64,000	128
Prepaid Royalties	746,400	1,493
Initial Catalyst and Chemicals	2,700	5
Startup	300	1
Spare Parts	13,300	27
Working Capital	-	-
Land 200 Acres	10,700	21
TOTAL CAPITAL REQUIREMENT	-	-
Total Capital Requirement $/kW	773,400	1,547
Illinois #6 coal; 2 -50% trains of gasification; Advanced H turbine; cold gas cleaning (MDEA, CLAUS, SCOTT to elemental sulfur)		

Costs shown on Exhibit A-11 are from the DOE/NETL report "Evaluation of Innovative Fossil Fuel Power Plants with CO_2 Removal", 1000316, December 2000. Co-sponsors are U.S. DOE/NETL and EPRI. The costs have been escalated to the end of 2004 and adjusted to 500 MW net generation consistent with the process utilized for data in Exhibit A-10. From the two exhibits one may concluded that a reasonable Total Capital Cost would be $1,600 per kW, on a higher heating value basis. The higher cost value considers the GE Energy gasifier estimates only having a single gasifier train. The efficiency value may be optimistic in view of the relatively advanced turbines selected for the two cases.

Exhibit A-12 presents a compilation of data for the current study. Except for the first two items, which are summations of data in Exhibits A-10 and 11, the costs are raw data from the publications; they are not escalated or adjusted for plant size. However, the data is reasonably recent, and sizes are near the 500 MW nominal scale.

The data illustrates the cost variations for IGCC plants, even within the same category of gasifier. Design philosophies are important, especially the selection of gasification trains – a single train versus two 50% trains. Also, because of the relatively immature nature of the technology, some cases include spare gasification units as backup for planned and unplanned shutdowns.

Coal Quality and Cost

The great preponderance of engineering assessments for IGCC systems has been performed using bituminous coals as the feedstock. Because the gasifier vessel typically operates under pressure – from 400 to 1000 psia, and temperatures in the range of 2,500 F, two of the most widely used technologies have selected a coal/solids and water slurry feed to facilitate introduction of the solids into the gasifier. The third commercial unit developed by Shell and it licensee, Uhde, uses a lockhopper system to feed the solid fuel into the reactor. The feed for the Shell gasifier must be dried to about 5% total moisture to prevent material handling problems. The drying process for subbituminous and lignite coals can present technical problems, adds to the cost, and requires emission control.

In addition to the material handling issues and energy losses to evaporate excess water from the low rank coals, the water also increases the amount of oxygen that must be produced, again increasing costs and consuming more auxiliary power.

GE Energy has in the past declined to provide data for subbituminous and lignite coals as a feed for their gasifier. ConocoPhillips has claimed to be able to use subbituminous coals and are not clear about using lignite. For these various reasons, in this study, the GE Energy gasifier with radiant and convective heat recovery was chosen for the bituminous and subbituminous coals, and Shell is used with lignite.

To estimate costs for the three study coals, data shown on Exhibit A-12 from the studies by the Canadian Clean Power Coalition and EPRI was examined. The EPRI data appears to be the more consistent with experience at Nexant and Bechtel. The Canadian work is proprietary and details are not available. It is not clear that all of the impacts of the lignite, for example, have been accounted for in the cost or performance results. In an EIA report on the work, some of the results were either misprinted, or do not seem reasonable.

Exhibit A-12, Comparison of IGCC Cost Data $1,000s

Data Sources	Installed Cost	Total Plant Cost	Total Plant Cost $/kW	Total Plant Investment	Total Capital Requirement	Total Capital Requirement $/kW	% Efficiency HHV	MW Net	Feedstock
1. Texaco Gasifier IGCC Base Case; Escalated to 2004; Adjusted to 500 MW nominal size:[1,2]									
Quench Heat Recovery	462,635	592,173	1,184	665,207	692,507	1,385	39.7%	500	Illinois #6
Rad. + Conv. Heat Recovery	551,058	682,241	1,266	769,321	799,521	1,483	43.5%	539	Illinois #6
2. ConnocoPhillips with H Turbine Escalated to 2004; Adjusted to nominal 500 MW:[1,3]	533,100	682,400	1,365	764,288	795,654	1,591	43.1%	500	Illinois #6
3. IGCC Plant Cost and Performance Estimates:[4]									
ConocoPhillips with Spare			1,440			1,710	37.4%	500	Illinois #6
ConocoPhillips w/o Spare			1,330			1,580	37.4%	500	Illinois #6
ConocoPhillips with Spare			1,350			1,610	39.6%	500	Pittsburgh #8
ConocoPhillips w/o Spare			1,250			1,490	39.6%	500	Pittsburgh #8
4. 3/2005 GCEP Presentation, Neville Holt, EPRI, 2002 Data, all cases have spare gasifier.									
GE Quench (Texaco) 512 MW			1,300			Not Reported	36.7%	512	Pittsburgh #8
GE (Texaco) Radiant 550 MW			1,550			Not Reported	39.3%	550	Pittsburgh #8
ConocoPhillips 520 MW			1,350			Not Reported	39.6%	520	Pittsburgh #8
Shell 530 MW			1,650			Not Reported	40.7%	530	Pittsburgh #8
5. Canadian Clean Power Coalition[5]									
GE Energy Quench, 425 MW Net, Bituminous Coal			Not Reported			1,410	37.6%	425	Bituminous Coal

Data Sources	Installed Cost	Total Plant Cost	Total Plant Cost $/kW	Total Plant Investment	Total Capital Requirement	Total Capital Requirement $/kW	% Efficiency HHV	MW Net	Feedstock
GE Energy Quench, 425 MW Net, Subbituminous Coal			Not Reported			1,502	37.7%	425	Subbit. Coal
Shell Solid Feed Gasifier 425 MW Net, Lignite			Not Reported			1,644	37.8%	425	Lignite
6. IGCC Studies of CO_2 Capture for Sequestration:[6]									
Petroleum coke; 2 x Gasifier			1,276			Not Reported	40.8%	513	Petroleum coke
Pittsburgh #8; 2 x Gasifier			1,254			Not Reported	40.8%	524	Pittsburgh #8
Illinois #6; 2 x Gasifier			1,364			Not Reported	38.4%	522	Illinois #6
Powder River Basin Subbituminous; 3 x Gasifier			1,551			Not Reported	35.7%	520	PRB Subbit.
Lignite; 4 x Gasifier			1,738			Not Reported	33.4%	507	Lignite
ConocoPhillips Gasifier									

NOTES:

1. Items 1 and 2 are revised for this study. Other data is as published in the source materials.
2. "Texaco Gasifier IGCC Base Case," PED-IGCC-98-001, U.S. DOE/NETL, June 2000
3. ""Evaluation of Innovative Fossil Fuel Power Plants with CO_2 Removal," 1000316, U.S. DOE/NETL and EPRI, December 2000 (Updated 2002)
4. G. Booras and N. Holt, "Pulverized Coal and IGCC Plant Cost and Performance," Gasification Technologies, Washington, DC, October 3-6, 2004
5. "Phase I Executive Summary," Canadian Clean Power Coalition, May 2004
6. N. Holt, et al., "Summary of Recent IGCC Studies of CO_2 Capture for Sequestration," Gasification Technologies Conference, San Francisco, CA, October 14, 2003

Exhibit A-13 presents the cost results for the present study.

Exhibit A-13, IGCC Costs and Coal Quality

	GE Energy IGCC Bituminous 500 MW Net	GE Energy IGCC Subbituminous 500 MW Net	Shell IGCC Lignite 500 MW Net
Total Plant Cost $/kW	1,430	1,630	2,000
Total Plant Investment $/kW	1,610	1,840	2,260
Total Capital Requirement $/kW	1,670	1,910	2,350
Operating Costs $1,000s	27,310	29,700	34,000

Costs in Exhibit A-13 are for the GE Energy IGCC with radiant and convective heat recovery. Two 50% gasification trains are included for both the GE and Shell systems. While not done for the present study, it could be reasonable to add a higher level of risk, and thus contingency cost to the Shell and lignite plant. However, the costs are already so high that the option is unlikely to be commercially feasible. The Canadians appear to have switched from the assessment of gasification for lignites to the potential use of supercritical fluidized bed units. SaskPower is conducting a study for one of their plants that will evaluate the supercritical circulating fluidized bed option.

Cost Uncertainty

In addition to the typical project and process related uncertainties, the gasification technology costs may also vary because the estimates for permits, licenses, and other preliminary engineering items are not well defined. For example, gasification developers may charge significant amounts for coal tests and engineering “packages” that a power generator might use to evaluate technologies.

The questions about cost and performance guarantees still need to be answered. The three major gasification developers have teamed with engineering firms and plant component suppliers in an effort to structure the power plant so that performance and cost can be firmly established as is tradition for the power industry. Exactly how the guarantees will be negotiated and accepted by industry remains to be decided, but without some reasonable agreement on these points, arrangement of project financing will be difficult.

Gasification developers are presenting their technologies as the best option for carbon management by the power industry. Potential CO_2 regulations and carbon markets are other unknowns that make the costs uncertain and could at the minimum delay introduction into the power generation market.

Operating Cost

Operating costs from the Texaco Gasification report and other data were reviewed and updated for the study. The costs are presented in Exhibit A-14.

Exhibit A-14, Annual Operating and Maintenance Costs, $1,000s

IGCC O&M Items	High Sulfur Bituminous Coal	Subbituminous Coal	Lignite (Shell Technology)
Operating Labor	9,400	9,400	11,300
Maintenance	14,700	16,800	18,700
Administrative & Support Labor	1,200	1,200	1,400
Consumables	2,010	2,300	2,600
TOTAL	27,310	29,700	34,000

As shown by the table, there is not a significant difference in O&M caused by coal type except that lignite and the Shell technology will be more costly to operate and maintain. The consumables include water, chemicals for the MDEA, Scott, Claus and other processes, miscellaneous consumables, and wastes disposal.

While not shown on the table because it is plant and location dependent, the fuel costs for the different coals would cause a much larger delta between the O&M costs. Typical costs for the three coals at the mines are approximately $1.50, $0.75, and $0.50 per million Btu for bituminous, subbituminous and lignite coals respectively. Delivered costs to the power plant are more varied because of transportation and market competition impacts.

The exhibits in this appendix present the raw data for air emission limits summarized from recent air permits and other related documents.[73] Exhibit A presents criteria pollutants; Exhibit B has 3 tables and shows non-criteria pollutants. The following items provide further explanations of the data presented:

- For major pollutants, each emission value has been listed followed by the control device or method. For example in the first item the notation "0.15 pound per million Btu, Wet Flue Gas Desulfurization (Wet FGD)" is used in the SO_2 column.

- Blanks in the tables indicate that no data was found in the documents.

- Emission values listed, especially for criteria pollutants, mostly represent the actual emission limits provided in the permit documents. For certain emission values, data provided in the permit documents were used to convert these values to show them in consistent units for different plants.

- For some plants, more than one emission limit is provided in the permit documents for the same air pollutant. For example, two SO_2 emission limits may be provided for a plant based on different averaging periods (e.g., one based on a 24-hour rolling average and the other on a 30-day rolling average). In such cases, only the most stringent emission limit has been shown in the exhibits.

- The permit documents were examined to obtain emission values for all important air pollutants. However, for certain pollutants, either these documents did not contain any limits or the information was not provided in terms of actual limits that could be reported. These pollutants included fine particulate ($PM_{2.5}$), sulfur trioxide, silica, and hydrogen sulfide. In lieu of sulfur trioxide, the documents contained limits on sulfuric acid emissions, which are reported.

[73] The permit documents reflect the information available as of February 2006. The reader should refer to the EPA RACT/BACT/LAER Clearing House Website, http://cfpub1.epa.gov/rblc/htm/bl02.cfm, and specific State websites to learn about permits for newly proposed facilities and any changes to the permit documents presently covered in this report.

Exhibit A, Criteria Pollutants From Air Permits and Other Documents

Projects	Fuel	Nitrogen Oxides (NO_X)	Sulfur Dioxide (SO_2)	Carbon Monoxide (CO)	Particulate Matter (overall)[7]	Particulate Matter (PM_{10})[7]	Lead (Pb)
Elm Road, Wisconsin: Two 615 MW Supercritical Pulverized Coal (PC) Boilers[1,2]	Bituminous Coal	0.07 lb/MMBtu Selective Catalytic Reduction (SCR)	0.15 lb/MMBtu Wet Limestone Flue Gas Desulfurization (WL-FGD)	0.12 lb/MMBtu	0.018 lb/MMBtu Baghouse and a Wet Electrostatic Precipitator (Wet ESP)	0.018 lb/MMBtu Baghouse and a Wet ESP	7.9 lb/TBtu
Comanche Generating Station, Unit 3, Pueblo, Pueblo County, Colorado: Super Critical PC Boiler Nominally Rated at 7,421 MMBtu/hr[4]	Subbituminous Coal	0.08 lb/MMBtu SCR	0.10 lb/MMBtu Lime Spray Dryer	0.13 lb/MMBtu	0.020 lb/MMBtu Baghouse	0.0120 lb/MMBtu Baghouse	
Longview Power, LLC Monongalia County West Virginia: 6,114 MMBtu/hr PC boiler, 600 MW[5]	Bituminous Coal	489 lb/hr (0.08 lb/MMBtu)[3] SCR	917 lb/hr (0.15lb/MMBtu) (97% reduction)[3] WL-FGD	673 lb/hr (0.11 lb/MMBtu)[3]	110 lb/hr (0.018 lb/MMBtu)[3] Baghouse	110 lb/hr (0.018 lb/MMBtu)[3] Baghouse	0.109 lb/hr (17.83 lb/TBtu[3])[3]

Projects	Fuel	Nitrogen Oxides (NO_X)	Sulfur Dioxide (SO_2)	Carbon Monoxide (CO)	Particulate Matter (overall)[7]	Particulate Matter (PM_{10})[7]	Lead (Pb)
Prairie State Generating Station, Illinois: Two 750 MW PC units[6]	Bituminous, Illinois coal (Herrin No. 6)	0.07 lb/MMBtu SCR	0.182 lb/MMBtu (98% reduction)[3] WL-FGD	0.12 lb/MMBtu	0.015 lb/MMBtu Dry Electrostatic Precipitator (ESP) and Wet ESP	0.035 lb/MMBtu (includes filterable and condensable; a limit of as low as 0.018 lb/MMBtu may be set, based on a field test) ESP and Wet ESP	0.0678 lb/h (0.0000091 lb/MMBtu)[3]
Intermountain Power Generating Station Unit 3, Millard County, Delta, Utah: PC Unit, 950-gross MW (900-net MW)[8,9]	Bituminous Coal, Sub-Bituminous Coal, and Blend	0.07 lb/MMBtu SCR	0.1 lb/MMBtu WL-FGD	0.15 lb/MMBtu	0.012 lb/MMBtu Baghouse		0.00002 lb/MMBtu,
Indeck-Elwood Energy Center, Elwood, Illinois: Nominal 660-MW Plant with two CFB boilers[10]	Bituminous, Illinois Coal	0.10 lb/MMBtu CFB boiler technology and Selective Non-Catalytic Reduction (SNCR)	0.15 lb/MMBtu CFB boiler technology, limestone addition to the bed, and Baghouse	0.10 lb/MMBtu	0.015 lb/MMBtu Baghouse		
Plum Point Energy Station, Arkansas: One PC Boiler 550-800 MW[11, 12]	Subbituminous Coal	0.09lb/MMBtu SCR	0.16 lb/MMBtu Lime Spray Dryer	0.16 lb/MMBtu	0.018 lb/MMBtu Baghouse	0.02 lb/MMBtu Baghouse	2.56×10^{-5} lb/MMBtu

Projects	Fuel	Nitrogen Oxides (NO_X)	Sulfur Dioxide (SO_2)	Carbon Monoxide (CO)	Particulate Matter (overall)[7]	Particulate Matter (PM_{10})[7]	Lead (Pb)
Thoroughbred Generating Station, Central City, Kentucky: Two PC Units, 750 MW[13, 14]	Bituminous Coal	0.08 lb/MMBtu SCR	0.167 lb/MMBtu WL-FGD	0.10 lb/MMBtu	0.018 lb/MMBtu ESP and Wet ESP	0.018 lb/MMBtu ESP and Wet ESP	0.00000386 lb/MMBtu
TS Power Plant, Eureka County, Nevada: One PC Unit, 200 MW[5]	Subbituminous Coal	0.067 lb/MMBtu SCR	0.09 lb/MMBtu for coal with $\geq$ 0.45% sulfur content (0.065 lb/MMBtu for coal with $\leq$ 0.45% sulfur content) Lime Spray Dryer	0.15 lb/MMBtu		0.012 lb/MMBtu Baghouse	
Santee Cooper Cross Generating Station Units 3 and 4, Berkeley County, South Carolina: Two PC Units, 5,700 MMBtu/hr[5]	Bituminous Coal (Petroleum Coke and Synfuel as secondary fuels)	0.08 lb/MMBtu SCR	0.13 lb/MMBtu (95% reduction)[3] WL-FGD	0.16 lb/MMBtu	0.015 lb/MMBtu ESP	0.018 lb/MMBtu ESP	0.0000169 lb/MMBtu
Holocomb Unit 2, Finney Kansas: One PC Unit, 660 MW[5]	Subbituminous Coal	0.12 lb/MMBtu (0.08 lb/MMBtu after initial 18 months) SCR	0.12 lb/MMBtu (94% reduction)[3] Lime Spray Dryer	0.15 lb/MMBtu		0.018 lb/MMBtu (99,71% reduction)[3] Baghouse	

Projects	Fuel	Nitrogen Oxides (NO_X)	Sulfur Dioxide (SO_2)	Carbon Monoxide (CO)	Particulate Matter (overall)[7]	Particulate Matter (PM_{10})[7]	Lead (Pb)
Limestone Electric Generating Station Units 1 and 2, Limestone County, Texas: PC Units, 7,863 MMBtu/hr[5]	Lignite (amendments to include sub-bituminous and petroleum coke)	0.5 lb/MMBtu[3] Water Injection	0.82 lb/MMBtu[3] WL-FGD	0.11 lb/MMBtu[3]	0.03 lb/MMBtu[3] ESP		0.000033 lb/MMBtu[3]
Elm Road, Wisconsin, IGCC Unit, 600 MW[2]	Bituminous Coal	15 ppmvd, 15% oxygen Diluent Injection System	0.03 lb/MMBtu Amine-based Scrubbing System	0.030 lb/MMBtu	0.011 lb/MMBtu Water Scrubbing	0.011 lb/MMBtu Water Scrubbing	0.0000257 lb/MMBtu
Kentucky Pioneer Energy Facility, Trapp Kentucky: IGCC Unit,540 MW net[15, 16]	High-sulfur Kentucky bituminous coal and pelletized refuse-derived fuel (RDF)	0.0735 lb/MMBtu based on 15 ppm by volume at 15 % oxygen Diluent Injection System	0.032 lb/MMBtu (99% reduction[3]) Syngas Scrubbing	0.032 lb/MMBtu Syngas Cleanup System	0.011 lb/MMBtu Syngas Cleanup System	0.011 lb/MMBtu Syngas Cleanup System	0.00001 lb/MMBtu[3]
Polk Power Station, Polk County Florida: IGCC Unit 260 MW unit[17, 19, 20]	Bituminous Coal, Coke, Blends	15 ppmvd Diluent Injection System (0.055 lb/MMBtu[3])	0.17 lb/MMBtu (97% reduction[3]) Amine-based Scrubbing System	Syngas 25 ppmvd (0.046 lb/MMBtu[3])	0.007 lb/MMBtu Water Scrubbing	0.007 lb/MMBtu Water Scrubbing	2.41×10^{-6} lb/MMBtu
Southern Illinois Clean Energy Center, Williamson County, Illinois: IGCC Unit, 544-MW (net)[18]	Bituminous Coal (Illinois Coal)	0.059 lb/MMBtu based on 15 ppmvd @ 15% O_2 Diluent Injection System	0.033 lb/MMBtu (99.36% reduction) Amine-Based Scrubbing System	0.04 lb/MMBtu	0.00924 lb/MMBtu (99.9% reduction) Dry Filter	0.00924 lb/MMBtu (99.9% reduction) Dry Filter	0.000001 lb/MMBtu

Projects	Fuel	Nitrogen Oxides (NO_X)	Sulfur Dioxide (SO_2)	Carbon Monoxide (CO)	Particulate Matter (overall)[7]	Particulate Matter (PM_{10})[7]	Lead (Pb)
Cash Creek, Kentucky: IGCC Unit, 677 MW[4]	Bituminous Coal	0.058 lb/MMBtu (0.087 lb/MMBtu on natural gas used as backup fuel) Diluent Injection System	0.043 lb/MMBtu Amine-based Scrubbing System	0.036 lb/MMBtu	0.007 lb/MMBtu Water Scrubbing	0.007 lb/MMBtu Water Scrubbing	

Exhibit B 1 of 3, Non-Criteria Pollutants from Air Permits and Other Documents

Projects	Mercury (Hg)	Volatile Organic Compounds (VOC)	Chlorides (HCl)	Fluorides (HF)	Hydrogen Sulfide (H_2S)	Reduced sulfur compounds	Ammonia (NH_3)
Elm Road, Wisconsin: Two 615 MW Supercritical Pulverized Coal (PC) Boilers[1,2]	1.12 lb/TBtu Heat Input Baghouse, WL-FGD and SCR system	0.0035 lb/MMBtu	16.2 pounds per hour	0.00088 lb/MMBtu			5 ppm and 20 pounds per hour.
Comanche Generating Station, Unit 3, Pueblo, Pueblo County, Colorado: Super Critical PC Boiler Nominally Rated at 7,421 MMBtu/hr[4]	20 x 10^{-6} lb/MWh	0.0035 lb/MMBtu	0.00064 lb/MMBtu,	0.00049 lb/MMBtu			
Longview Power, LLC Monongalia County West Virginia: 6,114 MMBtu/hr PC boiler, 600 MW[5]	1.46x10^{-2} lb/hr (0.0000024 lb/MMBtu)[3]	24.5 lb/hr (0.004 lb/MMBtu)[3]	0.61 lb/hr (1.00x10^{-4} lb/MMBtu)[3]	0.61 lb/hr (1.00x10^{-4} lb/MMBtu)[3]			

Projects	Mercury (Hg)	Volatile Organic Compounds (VOC)	Chlorides (HCl)	Fluorides (HF)	Hydrogen Sulfide (H_2S)	Reduced sulfur compounds	Ammonia (NH_3)
Prairie State Generating Station, Illinois: Two 750 MW PC units[6]	0.016 lb/h (0.0000021 lb/MMBtu)[3]	0.004 lb/MMBtu	24.4 lb/h (0.0033 lb/MMBtu)[3]	0.00026 lb/MMBtu			
Intermountain Power Generating Station Unit 3, Millard County, Delta, Utah: PC Unit, 950-gross MW (900-net MW)[8,9]	0.00000014 lb/MMBtu[3] (6 x 10^{-6} lb/ MWh) bituminous coal; and 0.00000046 lb/MMBtu (20 x 10^{-6} lb/ MWh)[3] subbituminous coal	0.0027lb/MMBtu	0.0042lb/MMBtu[3], (38.13 lb/hr)	0.0005 lb/MMBtu		0.00073 lb/MMBtu[3], (6.62 lb/hr)	
Indeck-Elwood Energy Center, Elwood, Illinois: Nominal 660-MW Plant with two CFB boilers[10]	0.000002 lb/MMBtu Injection of powdered activated carbon or other similar material	0.004 lb/MMBtu or 11.7 lbs/hour	0.01 lb/million or such lower limit, as low as 0.006 lb/MMBtu, as set by the Illinois EPA following the Permittee's evaluation of hydrogen chloride emissions and the acid gas control system	CFB boiler technology, limestone addition to the bed, and baghouse			

Projects	Mercury (Hg)	Volatile Organic Compounds (VOC)	Chlorides (HCl)	Fluorides (HF)	Hydrogen Sulfide (H_2S)	Reduced sulfur compounds	Ammonia (NH_3)
Plum Point Energy Station, Arkansas: One PC Boiler 550-800 MW[11, 12]	0.0000131 lb/MMBtu[3]	0.02 lb/MMBtu	0.0131 lb/MMBtu[3]	0.00044 lb/MMBtu or 90% reduction[3]			
Thoroughbred Generating Station, Central City, Kentucky: Two PC Units, 750 MW[13, 14]	0.00000321 lb/MMBtu	0.0072 lb/MMBtu	0.000825 lb/MMBtu	0.000159 lb/MMBtu			
TS Power Plant, Eureka County, Nevada: One PC Unit, 200 MW[5]				1.17 lb/MMBtu			
Santee Cooper Cross Generating Station Units 3 and 4, Berkeley County, South Carolina: Two PC Units, 5,700 MMBtu/hr[5]	0.0000036 lb/MMBtu SCR/WL-FGD/ESP	0.0024 lb/MMBtu	0.0024 lb/MMBtu	0.0003 lb/MMBtu			
Holocomb Unit 2, Finney Kansas: One PC Unit, 660 MW[5]		0.0035 lb/MMBtu					
Limestone Electric Generating Station Units 1 and 2, Limestone County, Texas: PC Units, 7,863 MMBtu/hr[5]	0.000051 lb/MMBtu[3]	0.0067 lb/MMBtu[3]	0.0155 lb/MMBtu[3]	0.01 lb/MMBtu[3]			

Projects	Mercury (Hg)	Volatile Organic Compounds (VOC)	Chlorides (HCl)	Fluorides (HF)	Hydrogen Sulfide (H_2S)	Reduced sulfur compounds	Ammonia (NH_3)
Elm Road, Wisconsin, IGCC Unit, 600 MW[2]	0.56lb/TBtu Carbon bed or filter containing similar material	0.004 lb/MMBtu					
Kentucky Pioneer Energy Facility, Trapp Kentucky: IGCC Unit,540 MW net[15, 16]	0.080 milligrams per dry standard cubic meter, corrected to 7% oxygen (0.0000007 lb/MMBtu[3])	0.0044 lb/MMBTU.	25 ppm by volume corrected to 7% oxygen (dry basis)				
Polk Power Station, Polk County Florida: IGCC Unit 260 MW unit[17]	0.0034 lb/h (1.9 lb/TBtu[3])	0.0017 lb/MMBtu					
Southern Illinois Clean Energy Center, Williamson County, Illinois: IGCC Unit, 544-MW (net)[18]	0.547 lb/TBtu Carbon Bed	0.0031 lb/MMBtu	1124.3 lb/TBtu	92.09 lb/TBtu			
Cash Creek, Kentucky: IGCC Unit, 677 MW[4]	0.00687 lb/hr	0.006 lb/MMBtu					

Exhibit B 2 of 3 Non-Criteria Pollutants from Air Permits and Other Documents

Projects	Arsenic (As)	Beryllium (Be)	Manganese (Mn)	Cadmium (Cd)	Chromium (Cr)	Formaldehyde	Nickel (Ni)	Silica (Si)
Elm Road, Wisconsin: Two 615 MW Supercritical Pulverized Coal (PC) Boilers[1,2]	5.99 lb/TBtu[3]	0.35 lb/TBtu	12.3 lb/TBtu[3]	1.1 lb/TBtu[3]	8.9 lb/TBtu[3]	48.0 lb/TBtu[3]	8.41 lb/TBtu[3]	
Comanche Generating Station, Unit 3, Pueblo, Pueblo County, Colorado: Super Critical PC Boiler Nominally Rated at 7,421 MMBtu/hr[4]								
Longview Power, LLC Monongalia County West Virginia: 6,114 MMBtu/hr PC boiler, 600 MW[5]		5.46×10^{-3} lb/hr						
Prairie State Generating Station, Illinois: Two 750 MW PC units[6]		0.0085 lb/h (1.14 lb/TBtu)						
Intermountain Power Generating Station Unit 3, Millard County, Delta, Utah: PC Unit, 950-gross MW (900-net MW)[8,9]								

Projects	Arsenic (As)	Beryllium (Be)	Manganese (Mn)	Cadmium (Cd)	Chromium (Cr)	Formaldehyde	Nickel (Ni)	Silica (Si)
Indeck-Elwood Energy Center, Elwood, Illinois: Nominal 660-MW Plant with two CFB boilers[10]		Addressed by limitation on PM Baghouse						
Plum Point Energy Station, Arkansas: One PC Boiler 550-800 MW[11, 12]	25 lb/TBtu[3]	2.38 lb/TBtu[3]	3.57 lb/TBtu[3]	3.1 lb/TBtu[3]	16.67 lb/TBtu[3]	15.48 lb/TBtu[3]	16.67 lb/TBtu[3]	
Thoroughbred Generating Station, Central City, Kentucky: Two PC Units, 750 MW[13, 14]	0.883 lb/TBtu	0.9 lb/TBtu	20.92 lb/TBtu	0.365 lb/TBtu	10.48 lb/TBtu			
TS Power Plant, Eureka County, Nevada: One PC Unit, 200 MW[5]								
Santee Cooper Cross Generating Station Units 3 and 4, Berkeley County, South Carolina: Two PC Units, 5,700 MMBtu/hr[5]		0.844 lb/TBtu						
Holocomb Unit 2, Finney Kansas: One PC Unit, 660 MW[5]								

Projects	Arsenic (As)	Beryllium (Be)	Manganese (Mn)	Cadmium (Cd)	Chromium (Cr)	Formaldehyde	Nickel (Ni)	Silica (Si)
Limestone Electric Generating Station Units 1 and 2, Limestone County, Texas: PC Units, 7,863 MMBtu/hr[5]	22.0 lb/TBtu[3]	9.0 lb/TBtu[3]	156 lb/TBtu[3]	7.6 lb/TBtu[3]	6.2 lb/TBtu[3]		62.0 lb/TBtu[3]	
Elm Road, Wisconsin, IGCC Unit, 600 MW[2]								
Kentucky Pioneer Energy Facility, Trapp Kentucky: IGCC Unit,540 MW net[15, 16]	6.0 lb/TBtu[3]	0.6 lb/TBtu	4.0 lb/TBtu[3]	0.020 milligrams per dry standard cubic meter, corrected to 7% oxygen (5.0 lb/TBtu[3])	1.1 lb/TBtu[3]		310 lb/TBtu[3]	
Polk Power Station, Polk County Florida: IGCC Unit 260 MW unit[17]	0.0006 lb/h	0.0001 lb/h						
Southern Illinois Clean Energy Center, Williamson County, Illinois: IGCC Unit, 544-MW (net)[18]	0.457 lb/TBtu	0.062 lb/TBtu	7.02 lb/TBtu	0.415 lb/TBtu	3.48 lb/TBtu		4.51 lb/TBtu	
Cash Creek, Kentucky: IGCC Unit, 677 MW[4]								

Exhibit B 3 of 3 Non-Criteria Pollutants from Air Permits and Other Documents

Projects	Selenium (Se)	Vanadium (V)	Total Reduced Sulfur (TRS)	Opacity	Sulfuric acid mist emissions
Elm Road,, Wisconsin: Two 615 MW Supercritical Pulverized Coal (PC) Boilers[1,2]	48.54 lb/TBtu[3]			20% or number 1 on the Ringlemann	0.010 lb/MMBtu heat input FGD system and wet electrostatic precipitator
Comanche Generating Station, Unit 3, Pueblo, Pueblo County, Colorado: Super Critical PC Boiler Nominally Rated at 7,421 MMBtu/hr[4]				10%	0.0042 lb/mmBtu lime spray dryer followed by a baghouse
Longview Power, LLC Monongalia County West Virginia: 6,114 MMBtu/hr PC boiler, 600 MW[5]				10%	45.8 lb/hr (0.0075 lb/MMBtu) dry sorbent injection in conjunction with fabric filter
Prairie State Generating Station, Illinois: Two 750 MW PC units[6]					0.005 lb/MMBtu WL-FGD (WFGD) and Wet Electrostatic Precipitator (WESP)

Projects	Selenium (Se)	Vanadium (V)	Total Reduced Sulfur (TRS)	Opacity	Sulfuric acid mist emissions
Intermountain Power Generating Station Unit 3, Millard County, Delta, Utah: PC Unit, 950-gross MW (900-net MW)[8,9]			0.00073 lb/MMBtu[3], (6.62 lb/hr)		0.0044 lb/MMBtu
Indeck-Elwood Energy Center, Elwood, Illinois: Nominal 660-MW Plant with two CFB boilers[10]				20%	Addressed by limitation on SO_2 CFB boiler technology, limestone addition to the bed, and baghouse
Plum Point Energy Station, Arkansas: One PC Boiler 550-800 MW[11, 12]					0.0061 lb/MMBtu
Thoroughbred Generating Station, Central City, Kentucky: Two PC Units, 750 MW[13, 14]				20%	0.00497 lb/MMBtu

Projects	Selenium (Se)	Vanadium (V)	Total Reduced Sulfur (TRS)	Opacity	Sulfuric acid mist emissions
TS Power Plant, Eureka County, Nevada: One PC Unit, 200 MW[5]					2.06 lb/hr
Santee Cooper Cross Generating Station Units 3 and 4, Berkeley County, South Carolina: Two PC Units, 5,700 MMBtu/hr[5]					0.0014 lb/MMBtu
Holocomb Unit 2, Finney Kansas: One PC Unit, 660 MW[5]					
Limestone Electric Generating Station Units 1 and 2, Limestone County, Texas: PC Units, 7,863 MMBtu/hr[5]	0.00137 lb/MMBtu	0.000267 lb/MMBtu		15 %	
Elm Road, Gasification Combined Cycle Unit, Wisconsin: 600 MW[2]				0%	0.0005 lb/MMBtu

Projects	Selenium (Se)	Vanadium (V)	Total Reduced Sulfur (TRS)	Opacity	Sulfuric acid mist emissions
Kentucky Pioneer Energy Facility, Trapp Kentucky: IGCC Plant,540 MW net[15, 16]	1.4 lb/TBtu[3]				
Polk Power Station, Polk County Florida: IGCC Plant 260 MW unit				10%	55 lb/h
Southern Illinois Clean Energy Center, Williamson County, Illinois: IGCC Plant, 544-MW (net)[18]	12.5 lb/TBtu			20%	0.0042 lb/MMBtu
Cash Creek, Kentucky: IGCC Plant, 677 MW[4]					

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18. BACT Evaluation, Appendices D and E, Steelhead Energy, LLC, Southern Illinois Clean Air Energy Center, October 2004, by Sargent & Lundy.

19. The Tampa Electric Integrated Combined-Cycle Project, DOE Topical Report No. 6, October 1996

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Appendix C Energy and Material Balances

Appendix C presents the detailed energy and material (E&M) balance tables produced for the IGCC and PC plants. These tables were prepared with Nexant's spreadsheet model to estimate plant performances and validate the emissions values determined from air permits and other sources. Thus, the E&M balance tables may not equal other values used in the report either from rounding, differences in calculations, or the value may have been determined by other methods than the balance table models. The sources for emission values are documented in the text or footnotes as they are provided in the report.

The E&M balance for each IGCC and PC plant configuration includes a summary of major plant performance parameters as well as conditions of major flow streams. The flow stream numbers shown in each E&M correspond to the numbers shown in Exhibit 2-2, Integrated Gasification Combined Cycle Block Diagram, and Exhibit 2-4, Pulverized Coal Plant Block Diagram.

The major parameters covered in each E&M balance include the following:

- Plant thermal efficiencies, heat rates, power outputs, fuel consumption, and byproduct amount (if any)
- Amounts of solids, liquids, and gas constituents present in each flow stream
- Pressure, temperature, and energy content of each flow stream

IGCC Energy and Material Balances

GE Energy Slurry Feed Gasifier and Bituminous Coal – Summary

Cold Gas Efficiency	% HHV	77.8
Net Thermal Efficiency	% HHV	41.8
Net Heat Rate (HHV)	Btu/kWh	8,167
Gross Power	MW	564
Internal Power	MW	64
Steam Turbine	MW	127.5
Gas Turbine	MW	436.5
Fuel Required	lb/h	349,744
Sulfur By-product	lb/h	8,679

GE Energy Slurry Feed Gasifier and Bituminous Coal – E&M Balance

Stream	Stream No.	1 Raw Coal	2 Feed to Gasifier	3 Oxygen	4 Raw Gas	5 Clean Fuel Gas	6 GT Exhaust	7 Flue Gas to Stack	8 Slag to Disposal	9 Sulfur Product
Solids	Units									
Coal, daf	lb/h	275,913	275,913							
Bitumen		0	0							
Carbon/Char		0	0						1,115	
Ash/Slag		34,939	34,939						34,939	
Sorb/Flux		0	0						0	
$CaSO_4$		0	0						0	
Elem. Sulfur		0	0						0	8,679
Water		38,892	156,595						19,414	
Subtotal	lb/h	349,744	467,448						55,468	8,679
Gas	lb/h									
O_2				271,867	0	0	993,116	993,116		
N_2				12,527	16,910	16,840	4,649,773	4,649,773		
CO_2				0	150,553	112,291	770,555	811,951		
H_2O				0	95,498	197,995	432,672	432,672		
H_2				0	22,054	21,949	0	0		
CO				0	420,949	418,954	122	122		
CH_4				0	0	0	0	0		
C_2H_6				0	0	0	0	0		
H_2S				0	8,667	87	0	0		
COS				0	1,149	11	0	0		
SO_2				0	0		175	175		
NO_2				0	0	0	200	200		
Subtotal	lb/h	0	0	284,393	715,780	768,129	6,846,612	6,888,008	0	0
Total	lb/h	349,744	467,448	284,393	715,780	768,129	6,846,612	6,888,008	55,468	8,679

Stream	Stream No.	1 Raw Coal	2 Feed to Gasifier	3 Oxygen	4 Raw Gas	5 Clean Fuel Gas	6 GT Exhaust	7 Flue Gas to Stack	8 Slag to Disposal	9 Sulfur Product
Pressure	psia	15	609	537	464	450	15	15	15	15
Temperature	°F	77	158	307	2,606	572	1,107	248	77	77
Total Energy	mmBtu/h	4,083	4,113	17	4,050	4,097	2,433	838	18	35

Stream	Stream No.	10 Cooling Water	11 CT Make Up Water	12 Waste Water Discharge
Solids	Units			
Coal, daf	lb/hr			
Bitumen				
Carbon/Char				
Ash/Slag				
Sorb/Flux				
$CaSO_4$				
Elem. Sulfur				
Water	lb/hr	17,675,601	1,586,094	13,328
Subtotal	lb/hr	17,675,601	1,586,094	13,328
Gas				
O_2				
N_2				
CO_2				
H_2O				
H_2				
CO				

Stream	Stream No.	10 Cooling Water	11 CT Make Up Water	12 Waste Water Discharge
CH_4				
C_2H_6				
H_2S				
COS				
SO_2				
NO_2				
Subtotal	lb/hr	0	0	0
Total	lb/hr	17,675,601	1,586,094	13,328
Pressure	psia	65	50	30
Temperature	^oF	115	80	80
Total Energy	mmBtu/h	1,502	81	0.7

GE Energy Slurry Feed Gasifier and Subbituminous Coal - Summary

Cold Gas Efficiency	% HHV	69.1
Net Thermal Efficiency	% HHV	40.0
Net Heat Rate (HHV)	Btu/kWh	8,520
Gross Power	MW	575
Internal Power	MW	75
Steam Turbine	MW	160
Gas Turbine	MW	415
Fuel Required	lb/h	484,089
Sulfur By-product	lb/h	1,044

GE Energy Slurry Feed Gasifier and Subbituminous Coal – E&M Balance

Stream	Stream No.	1 Raw Coal	2 Feed to Gasifier	3 Oxygen	4 Raw Gas	5 Clean Fuel Gas	6 GT Exhaust	7 Flue Gas to Stack	8 Slag to Disposal	9 Sulfur Product
Solids	Units									
Coal, daf	lb/h	329,568	329,568							
Bitumen		0	0							
Carbon/Char		0	0						1,216	
Ash/Slag		21,881	21,881						21,881	
Sorb/Flux		0	0						0	
$CaSO_4$		0	0						0	
Elem. Sulfur		0	0						0	1,044
Water		132,641	298,055						12,437	
Subtotal	lb/h	484,089	649,503	0	0	0	0	0	35,534	1,044

Stream	Stream No.	1 Raw Coal	2 Feed to Gasifier	3 Oxygen	4 Raw Gas	5 Clean Fuel Gas	6 GT Exhaust	7 Flue Gas to Stack	8 Slag to Disposal	9 Sulfur Product
Gas	lb/h									
O_2				325,115	0	0	934,053	934,053		
N_2				14,980	18,143	18,069	4,355,256	4,355,256		
CO_2				0	321,041	239,462	802,488	886,729		
H_2O				0	243,526	67,804	304,477	304,477		
H_2				0	22,557	22,451	0	0		
CO				0	360,040	358,346	128	128		
CH_4				0	0	0	0	0		
C_2H_6				0	0	0	0	0		
H_2S				0	1,042	10	0	0	2,109	
COS				0	138	1	0	0		
SO_2				0	0		51	51		
NO_2				0	0	0	188	188		
Subtotal	lb/h	0	0	340,095	966,488	706,144	6,396,641	6,480,882	2,109	0
Total	lb/h	484,089	649,503	340,095	966,488	706,144	6,396,641	6,480,882	37,643	1,044
Pressure	psia	15	609	537	464	450	15	15	15	15
Temperature	°F	77	158	307	2,606	572	1,108	248	77	77
Total Energy	mmBtu/h	4,260	4,309	21	4,257	2,463	2,143	671	19	4

Stream	Stream No.	10 Cooling Water	11 CT Make Up Water	12 Waste Water Discharge
Solids	Units			
Coal, daf	lb/hr			
Bitumen				
Carbon/Char				
Ash/Slag				
Sorb/Flux				
$CaSO_4$				
Elem. Sulfur				
Water		22,195,009	1,982,121	10580
Subtotal	lb/hr	22,195,009	1,982,121	10,580
Gas	lb/hr			
O_2				
N_2				
CO_2				
H_2O				
H_2				
CO				
CH_4				
C_2H_6				
H_2S				
COS				
SO_2				
NO_2				
Subtotal	lb/hr	0	0	0
Total	lb/hr	22,195,009	1,982,121	10,580
Pressure	psia	65	50	30
Temperature	^oF	115	80	80
Total Energy	mmBtu/h	1,887	100	0.8

Shell Solid Feed Gasifier and Lignite Coal - Summary

Cold Gas Efficiency	% HHV	78.4
Net Thermal Efficiency	% HHV	39.2
Net Heat Rate (HHV)	Btu/kWh	8,707
Gross Power	MW	580
Internal Power	MW	80
Steam Turbine	MW	221
Gas Turbine	MW	359
Fuel Required	lb/h	689,721
Sulfur By-product	lb/h	4,370

Shell Solid Feed Gasifier and Lignite Coal – E&M Balance

Stream	Stream No.	1 Raw Coal	2 Feed to Gasifier	3 Oxygen	4 Raw Gas	5 Clean Fuel Gas	6 GT Exhaust	7 Flue Gas to Stack	8 Slag to Disposal	9 Sulfur Product
Solids	Units									
Coal, daf	lb/h	350,654	350,654							
Bitumen			0							
Carbon/Char									501	
Ash/Slag		123,598	123,598						123,598	
Sorb/Flux			0						0	
$CaSO_4$									0	
Elem. Sulfur										4,370
Water		215,469	24,961						66,822	
Subtotal	lb/h	689,721	499,213						190,921	4,370

Stream	Stream No.	1 Raw Coal	2 Feed to Gasifier	3 Oxygen	4 Raw Gas	5 Clean Fuel Gas	6 GT Exhaust	7 Flue Gas to Stack	8 Slag to Disposal	9 Sulfur Product
Gas	lb/h									
O_2				273,807	0	0	1,083,611	1,083,611		
N_2				12,616	55,196	54,596	5,079,109	5,079,109		
CO_2				0	69,698	51,516	887,239	915,121		
H_2O				0	14,608	230,435	427,727	427,727		
H_2					17,603	17,401				
CO					538,044	531,871	131	131		
CH_4					15	15				
C_2H_6					0	0				
H_2S					4,363	44				
COS					578	6			8,747	
SO_2							87	87		
NO_2							218	218		
Subtotal	lb/h			286,423	700,107	885,884	7,476,794	7,506,322	8,747	
Total	lb/h	689,721	499,213	286,423	700,107	885,884	7,476,794	7,506,322	199,668	4,370
Pressure	psia	15	537	464	392	377	15	15	15	15
Temperature	°F	77	158	298	2,939	572	1,106	248	77	77
Total Energy	mmBtu/h	4,354	4,371	17	4,191	2,419	2,596	865	12	17

Stream	Stream No.	10 Cooling Water	11 CT Make Up Water	12 Waste Water Discharge
Solids	Units			
Coal, daf	lb/hr			
Bitumen				

Stream	Stream No.	10 Cooling Water	11 CT Make Up Water	12 Waste Water Discharge
Carbon/Char				
Ash/Slag				
Sorb/Flux				
$CaSO_4$				
Elem. Sulfur				
Water	lb/hr	30,637,708	2,848,710	29,494
Subtotal	lb/hr	30,637,708	2,848,710	29,494
Gas				
O_2				
N_2				
CO_2				
H_2O				
H_2				
CO				
CH_4				
C_2H_6				
H_2S				
COS				
SO_2				
NO_2				
Subtotal	lb/hr	0	0	0
Total	lb/hr	30,637,708	2,848,710	29,494
Pressure	psia	65	50	30
Temperature	^oF	115	80	80
Total Energy	mmBtu/h	1,441	46	0.6

PC Plant Energy and Material Balances

Subcritical PC and Bituminous Coal - Summary

Summary		
Net Thermal Efficiency	35.9	% HHV
Net Heat Rate (HHV)	9,500	Btu/kWh
Gross Power	540	MW
Internal Power	40	MW
Fuel required	407,143	lb/h
Net Power	500	MW

Subcritical PC and Bituminous Coal – E&M Balance

Stream	Stream No.	1 Coal Feed	2 Combustion Air	3 HP Steam to T/G	4 Bottom Ash	5 Flue Gas to Filter	6 Ash From Filter	7 Flue Gas to FGD	8 Limestone to FGD	9 Gypsum from FGD
Solids	Units									
Coal, daf	lb/h	321,195	0	0	0	0	0	0	0	0
Sorbent		0	0	0	0	0	0	0	36,194	0
Ash/Slag		40,674	0	0	8,427	33,707	33,232	475	0	0
$CaSO_4.2H_2O$		0	0	0	0	0	0	0	0	54,086

Stream	Stream No.	1 Coal Feed	2 Combustion Air	3 HP Steam to T/G	4 Bottom Ash	5 Flue Gas to Filter	6 Ash From Filter	7 Flue Gas to FGD	8 Limestone to FGD	9 Gypsum from FGD
Water		45,274	0	3,571,590	0	0	0	0	0	6,010
Subtotal	lb/h	407,143	0	3,571,590	8,427	33,707	33,232	475	36,194	60,095
Gas										
O_2		0	1,002,292	0	0	183,426	0	183,426	0	0
N_2		0	3,302,954	0	0	3,308,035	0	3,308,035	0	0
CO_2		0	0	0	0	946,162	0	946,162	0	0
H_2O		0	27,419	0	0	245,089	0	227,859	0	0
SO_2		0	0	0	0	20,391	0	20,391	0	0
NO_2		0	0	0	0	285	0	285	0	0
Subtotal	lb/h	0	4,332,665	0	0	4,703,387	0	4,686,158	0	0
TOTAL	lb/h	407,143	4,332,665	3,571,590	8,427	4,737,094	33,232	4,686,633	36,194	60,095
Pressure	psia	14.7	14.7	2,415	14.7	14.0	14.7	15.0	14.7	14.7
Temperature	°F	59	59	1,000	2,498	288	287	302	32	86
Total Energy	mmBtu/h	4,753	58	5,216	12	583	18	561	0	1

Stream	Stream No.	10 Flue Gas to Stack	11 Reheat Steam to T/G	12 Turbine Exhaust to Condenser	13 Cooling Water to Condenser	14 Cooling Tower Evaporative Loses	15 Cooling Tower Blowdown	16 Waste Water (from Process)
Solids	Units							
Coal, daf	lb/h	0						
Sorbent		0						
Ash/Slag		57						
$CaSO_4.2H_2O$		0						
Water		0	3,250,147	2,762,625	74,518,170	3,058,656	1,512,294	38,461
Subtotal	lb/h	57	3,250,147	2,762,625	74,518,170	3,058,656	1,512,294	38,461
Gas								

Stream	Stream No.	10 Flue Gas to Stack	11 Reheat Steam to T/G	12 Turbine Exhaust to Condenser	13 Cooling Water to Condenser	14 Cooling Tower Evaporative Loses	15 Cooling Tower Blowdown	16 Waste Water (from Process)
O_2		183,426						
N_2		3,308,035						
CO_2		958,769						
H_2O		429,620						
SO_2		409						
NO_2		285						
Subtotal	lb/h	4,880,543	0	0	0	0	0	0
TOTAL	lb/h	4,880,600	3,250,147	2,762,625	74,518,170	3,058,656	1,512,294	38,461
Pressure	psia	14.7	560.0	115	55	25	15	15
Temperature	°F	128	1,000	1.50	80	118	80	70
Total Energy	mmBtu/h	580	4,934	2,832	2,832	3120	73	2

Subcritical PC and Subbituminous Coal - Summary

Summary		
Net Thermal Efficiency	34.8	% HHV
Net Heat Rate (HHV)	9,800	Btu/kWh
Gross Power	541	MW
Internal Power	41	MW
Fuel required	556,818	lb/h
Net Power	500	MW

Subcritical PC and Subbituminous Coal – E&M Balance

Stream	Stream No.	1 Coal Feed	2 Combustion Air	3 HP Steam to T/G	4 Bottom Ash	5 Flue Gas SDA	6 Lime to SDA	7 SDA Filter Waste	8 Flue Gas To Stack
Solids	Units								
Coal, daf	lb/h	379,082	0	0	0	0	0	0	0
Sorbent		0	0	0	0	0	4,242	0	0
Ash/Slag		25,168	0	0	5,421	21,686	0	21,627	59
$CaSO_4.2H_2O$		0	0	0	0	0	0	13,029	0
Water		152,568	0	3,577,159	0	0	21,210		0
Subtotal	lb/h	556,818	0	3,577,159	5,421	21,686	25,452	34,656	59
Gas									
O_2		0	987,528	0	0	180,724	0	0	180,724
N_2		0	3,254,301	0	0	3,257,947	0	0	3,257,947
CO_2		0	0	0	0	1,026,489	0	0	1,028,081
H_2O		0	27,015	0	0	318,550	0	0	504,140

Stream	Stream No.	1 Coal Feed	2 Combustion Air	3 HP Steam to T/G	4 Bottom Ash	5 Flue Gas SDA	6 Lime to SDA	7 SDA Filter Waste	8 Flue Gas To Stack
SO_2		0	0	0	0	2,438	0	0	319
NO_2		0	0	0	0	2,94	0	0	294
Subtotal	lb/h	0	4,268,845	0	0	4,786,443	0	0	4,971,505
TOTAL	lb/h	556,818	4,268,845	3,577,159	5,421	4,808,129	25,452	34,656	4,971,564
Pressure	psia	14.7	14.7	2,415	14.7	15.0	14.7	14.7	14.7
Temperature	°F	59	59	1,000	2,498	270	59	86	132
Total Energy	mmBtu/h	4,649	57	5,224	11	630	0	0	699

Stream	Stream No.	9 Reheat Steam to T/G	10 Turbine Exhaust to Condenser	11 Cooling Water to Condenser	12 Cooling Tower Evaporative Loses	13 Cooling Tower Blowdown	14 Waste Water (from Process)
Solids	Units						
Coal, daf	lb/h						
Sorbent							
Ash/Slag							
$CaSO_4.2H_2O$							
Water		3,255,214	2,766,932	74,634,356	3,160,892	1,563,107	7,818
Subtotal	lb/h	3,255,214	2,766,932	74,634,356	3,160,892	1,563,107	7,818
Gas							
O_2							
N_2							
CO_2							
H_2O							

Stream	Stream No.	9 Reheat Steam to T/G	10 Turbine Exhaust to Condenser	11 Cooling Water to Condenser	12 Cooling Tower Evaporative Loses	13 Cooling Tower Blowdown	14 Waste Water (from Process)
SO_2 NO_2							
Subtotal	lb/h	0	0	0	0	0	0
TOTAL	lb/h	3,255,214	2,766,932	74,634,356	3,160,892	1,563,107	7,818
Pressure	psia	560.0	115	55	25	15	15
Temperature	°F	1,000	1.50	80	118	80	70
Total Energy	mmBtu/h	4,941	2,836	2,836	3,225	75	0

Subcritical PC and Lignite Coal - Summary

Summary		
Net Thermal Efficiency	33.1	% HHV
Net Heat Rate (HHV)	10,300	Btu/kWh
Gross Power	544	MW
Internal Power	44	MW
Fuel required	815,906	lb/h
Net Power	500	MW

Subcritical PC and Lignite Coal – E&M Balance

Stream	Stream No.	1 Coal Feed	2 Combustion Air	3 HP Steam to T/G	4 Bottom Ash	5 Flue Gas to Filter	6 Ash From Filter	7 Flue Gas to FGD	8 Limestone to FGD	9 Gypsum from FGD
Solids	Units									
Coal, daf	lb/h	414,480	0	0	0	0	0	0	0	0
Sorbent		0	0	0	0	0	0	0	18,135	0
Ash/Slag		146,537	0	0	29,738	118,951	118,461	490	0	0
$CaSO_4.2H_2O$		0	0	0	0	0	0	0	0	30,741
Water		254,889	0	3,596,072	0	0	0	0	0	3,416
Subtotal	lb/h	815,906	0	3,596,072	29,738	118,951	118,461	490	18,135	34,156
Gas		0	0	0	0	0	0	0	0	0
O_2		0	1,055,749	0	0	193,209	0	193,209	0	0
N_2		0	3,479,117	0	0	3,484,871	0	3,484,871	0	0
CO_2		0	0	0	0	1,078,921	0	1,078,921	0	0
H_2O		0	28,881	0	0	469,265	0	449,785	0	0

Stream	Stream No.	1 Coal Feed	2 Combustion Air	3 HP Steam to T/G	4 Bottom Ash	5 Flue Gas to Filter	6 Ash From Filter	7 Flue Gas to FGD	8 Limestone to FGD	9 Gypsum from FGD
SO_2		0	0	0	0	10,424	0	10,424	0	0
NO_2		0	0	0	0	309	0	309	0	0
Subtotal	lb/h	0	4,563,748	0	0	5,237,000	0	5,217,520	0	0
TOTAL	lb/h	815,906	4,563,748	3,596,072	29,738	5,355,951	118,461	5,218,010	18,135	34,156
Pressure	psia	14.7	14.7	2,415	14.7	14.0	14.7	15.0	14.7	14.7
Temperature	°F	59	59	1,000	2,498	279	278	293	32	86
Total Energy	mmBtu/h	4,903	61	5,251	34	868	30	833	0	1

Stream	Stream No.	10 Flue Gas to Stack	11 Reheat Steam To T/G	12 Turbine Exhaust to Condenser	13 Cooling Water to Condenser	14 Cooling Tower Evaporative Loses	15 Cooling Tower Blowdown	16 Waste Water (from Process)
Solids	Units							
Coal, daf	lb/h	0						
Sorbent		0						
Ash/Slag		62						
$CaSO_4$.2H2O		0						
Water		0	3,272,426	2,781,562	75,028,976	3,341,047	1,651,773	21,860
Subtotal	lb/h	62	3,272,426	2,781,562	75,028,976	3,341,047	1,651,773	21,860
Gas								
O_2		193,209						
N_2		3,484,871						
CO_2		1,085,724						
H_2O		657,156						
SO_2		443						
NO_2		309						

Stream	Stream No.	10 Flue Gas to Stack	11 Reheat Steam To T/G	12 Turbine Exhaust to Condenser	13 Cooling Water to Condenser	14 Cooling Tower Evaporative Loses	15 Cooling Tower Blowdown	16 Waste Water (from Process)
Subtotal	lb/h	5,421,475	0	0	0	0	0	0
TOTAL	lb/h	5,421,537	3,272,426	2,781,562	75,028,976	3,341,047	1,651,773	21,860
Pressure	psia	14.7	560.0	115	55	25	15	15
Temperature	°F	139	1,000	1.50	80	118	80	70
Total Energy	mmBtu/h	857	4,968	2,851	2,851	3,408	79	1

Supercritical PC and Bituminous Coal - Summary

Summary		
Net Thermal Efficiency	38.3	% HHV
Net Heat Rate (HHV)	8,900	Btu/kWh
Gross Power	540	MW
Internal Power	40	MW
Fuel required	381,418	lb/h
Net Power	500	MW

Supercritical PC and Bituminous Coal – E&M Balance

Stream	Stream No.	1 Coal Feed	2 Combustion Air	3 HP Steam to T/G	4 Bottom Ash	5 Flue Gas to Filter	6 Ash From Filter	7 Flue Gas to FGD	8 Limestone to FGD	9 Gypsum from FGD
Solids	Units									
Coal, daf	lb/h	300,901	0	0	0	0	0	0	0	0
Sorbent		0	0	0	0	0	0	0	34,666	0
Ash/Slag		38,104	0	0	7,894	31,577	31,132	445	0	0
$CaSO_4.2H_2O$		0	0	0	0	0	0	0	0	51,802
Water		42,414	0	3,576,288	0	0	0	0	0	5,756
Subtotal	lb/h	381,418	0	3,576,288	7,894	31,577	31,132	445	34,666	57,558
Gas										

Stream	Stream No.	1 Coal Feed	2 Combustion Air	3 HP Steam to T/G	4 Bottom Ash	5 Flue Gas to Filter	6 Ash From Filter	7 Flue Gas to FGD	8 Limestone to FGD	9 Gypsum from FGD
O_2		0	938,963	0	0	171,836	0	171,836	0	0
N_2		0	3,094,261	0	0	3,099,021	0	3,099,021	0	0
CO_2		0	0	0	0	886,380	0	886,380	0	0
H_2O		0	25,687	0	0	230,135	0	213,993	0	0
SO_2		0	0	0	0	19,102	0	19,102	0	0
NO_2		0	0	0	0	267	0	267	0	0
Subtotal	lb/h	0	4,058,911	0	0	4,406,742	0	4,390,599	0	0
TOTAL	lb/h	381,418	4,058,911	3,576,288	7,894	4,438,319	31,132	4,391,045	34,666	57,558
Pressure	psia	14.7	14.7	3,515	14.7	14.0	14.7	15.0	14.7	14.7
Temperature	°F	59	59	1,050	2,498	288	287	302	32	86
Total Energy	mmBtu/h	4,453	54	5,083	11	546	17	526	0	1

Stream	Stream No.	10 Flue Gas to Stack	11 Reheat Steam to T/G	12 Turbine Exhaust to Condenser	13 Cooling Water to Condenser	14 Cooling Tower Evaporative Loses	15 Cooling Tower Blowdown	16 Waste Water (from Process)
Solids	Units							
Coal, daf	lb/h	0						
Sorbent		0						
Ash/Slag		54						
$CaSO_4.2H_2O$		0						
Water		0	3,254,422	2,766,259	74,616,184	2,880,487	1,423,633	36,837
Subtotal	lb/h	54	3,254,422	2,766,259	74,616,184	2,880,487	1,423,633	36,837
Gas								
O_2		171,836						
N_2		3,099,021						

Stream	Stream No.	10 Flue Gas to Stack	11 Reheat Steam to T/G	12 Turbine Exhaust to Condenser	13 Cooling Water to Condenser	14 Cooling Tower Evaporative Loses	15 Cooling Tower Blowdown	16 Waste Water (from Process)
CO_2		898,191						
H_2O		403,047						
SO_2		383						
NO_2		267						
Subtotal	lb/h	4,572,745	0	0	0	0	0	0
TOTAL	lb/h	4,572,799	3,254,422	2,766,259	74,616,184	2,880,487	1,423,633	36,837
Pressure	psia	14.7	560.0	115	55	25	15	15
Temperature	°F	128	1,000	1.50	80	118	80	70
Total Energy	mmBtu/h	544	4,940	2,835	2,835	2,938	68	2

Supercritical PC and Subbituminous Coal - Summary

Summary		
Net Thermal Efficiency	37.9	% HHV
Net Heat Rate (HHV)	9,000	Btu/kWh
Gross Power	541	MW
Internal Power	41	MW
Fuel required	517,045	lb/h
Net Power	500	MW

Supercritical PC and Subbituminous Coal – E&M Balance

Stream	Stream No.	1 Coal Feed	2 Combustion Air	3 HP Steam to T/G	4 Bottom Ash	5 Flue Gas SDA	6 Lime to SDA	7 SDA Filter Waste	8 Flue Gas To Stack
Solids	Units								
Coal, daf	lb/h	352,005	0	0	0	0	0	0	0
Sorbent		0	0	0	0	0	3,939	0	0
Ash/Slag		23,370	0	0	5,034	20,137	0	20,082	54
$CaSO_4.2H_2O$		0	0	0	0	0	0	12,099	0
Water		141,670	0	3,581,627	0	0	19,695	0	0
Subtotal	lb/h	517,045	0	3,581,627	5,034	20,137	23,634	32,181	54
Gas									
O_2		0	916,991	0	0	167,815	0	0	167,815
N_2		0	3,021,853	0	0	3,025,239	0	0	3,025,239
CO_2		0	0	0	0	953,169	0	0	954,647
H_2O		0	25,086	0	0	312,611	0	0	471,206

Stream	Stream No.	1 Coal Feed	2 Combustion Air	3 HP Steam to T/G	4 Bottom Ash	5 Flue Gas SDA	6 Lime to SDA	7 SDA Filter Waste	8 Flue Gas To Stack
SO_2		0	0	0	0	2,264	0	0	293
NO_2		0	0	0	0	271	0	0	271
Subtotal	lb/h	0	3,963,930	0	0	4,461,369	0	0	4,619,472
TOTAL	lb/h	517,045	3,963,930	3,581,627	5,034	4,481,506	23,634	32,181	4,619,526
Pressure	psia	14.7	14.7	3,515	14.7	14.0	14.7	14.7	14.7
Temperature	°F	59	59	1,050	2,498	256	32	86	132
Total Energy	mmBtu/h	4,550	55	5,091	10	643	0	0	635

Stream	Stream No.	9 Reheat Steam to T/G	10 Turbine Exhaust To Condenser	11 Cooling Water to Condenser	12 Cooling Tower Evaporative Loses	13 Cooling Tower Blowdown	14 Waste Water (from Process)
Solids	Units						
Coal, daf	lb/h						
Sorbent							
Ash/Slag							
$CaSO_4.2H_2O$							
Water		3,259,280	2,770,388	74,727,581	2,918,205	1,442,063	7,259
Subtotal	lb/h	3,259,280	2,770,388	74,727,581	2,918,205	1,442,063	7,259
Gas							
O_2							
N_2							
CO_2							
H_2O							
SO_2							
NO_2							

Stream	Stream No.	9 Reheat Steam to T/G	10 Turbine Exhaust To Condenser	11 Cooling Water to Condenser	12 Cooling Tower Evaporative Loses	13 Cooling Tower Blowdown	14 Waste Water (from Process)
Subtotal	lb/h	0	0	0	0	0	0
TOTAL	lb/h	3,259,280	2,770,388	74,727,581	2,918,205	1,442,063	7,259
Pressure	psia	560.0	115	55	25	15	15
Temperature	°F	1,000	1.50	80	118	80	70
Total Energy	mmBtu/h	4,948	2,840	2,840	2,977	69	0

Supercritical PC and Lignite Coal - Summary

Summary		
Net Thermal Efficiency	35.9	% HHV
Net Heat Rate (HHV)	9,500	Btu/kWh
Gross Power	544	MW
Internal Power	44	MW
Fuel required	752,535	lb/h
Net Power	500	MW

Supercritical PC and Lignite Coal – E&M Balance

Stream	Stream No.	1 Coal Feed	2 Combustion Air	3 HP Steam to T/G	4 Bottom Ash	5 Flue Gas to Filter	6 Ash From Filter	7 Flue Gas to FGD	8 Limestone to FGD	9 Gypsum from FGD
Solids	Units									
Coal, daf	lb/h	382,288	0	0	0	0	0	0	0	0
Sorbent		0	0	0	0	0	0	0	16,727	0
Ash/Slag		135,155	0	0	27,428	109,712	109,260	452	0	0
$CaSO_4.2H_2O$		0	0	0	0	0	0	0	0	29,432
Water		235,092	0	3,599,756	0	0	0	0	0	3,270
Subtotal	lb/h	752,535	0	3,599,756	27,428	109,712	109,260	452	16,727	32,702
Gas										

Stream	Stream No.	1 Coal Feed	2 Combustion Air	3 HP Steam to T/G	4 Bottom Ash	5 Flue Gas to Filter	6 Ash From Filter	7 Flue Gas to FGD	8 Limestone to FGD	9 Gypsum from FGD
O_2		0	973,749	0	0	178,202	0	178,202	0	0
N_2		0	3,208,895	0	0	3,214,201	0	3,214,201	0	0
CO_2		0	0	0	0	995,122	0	995,122	0	0
H_2O		0	26,638	0	0	433,358	0	415,389	0	0
SO_2		0	0	0	0	9,615	0	9,615	0	0
NO_2		0	0	0	0	285	0	285	0	0
Subtotal	lb/h	0	4,209,282	0	0	4,830,786	0	4,812,814	0	0
TOTAL	lb/h	752,535	4,209,282	3,599,756	27,428	4,940,495	109,260	4,813,266	16,727	32,702
Pressure	psia	14.7	14.7	3,515	14.7	14.0	14.7	15.0	14.7	14.7
Temperature	°F	59	59	1,050	2,498	279	278	293	32	86
Total Energy	mmBtu/h	4,774	59	5,117	33	846	30	812	0	1

Stream	Stream No.	10 Flue Gas to Stack	11 Reheat Steam To T/G	12 Turbine Exhaust to Condenser	13 Cooling Water to Condenser	14 Cooling Tower Evaporative Loses	15 Cooling Tower Blowdown	16 Waste Water (from Process)
Solids	Units							
Coal, daf	lb/h	0						
Sorbent		0						
Ash/Slag		57						
$CaSO_4.2H_2O$		0						
Water		0	3,275,778	2,784,411	75,105,834	3,097,367	1,530,729	20,929
Subtotal	lb/h	57	3,275,778	2,784,411	75,105,834	3,097,367	1,530,729	20,929
Gas								

Stream	Stream No.	10 Flue Gas to Stack	11 Reheat Steam To T/G	12 Turbine Exhaust to Condenser	13 Cooling Water to Condenser	14 Cooling Tower Evaporative Loses	15 Cooling Tower Blowdown	16 Waste Water (from Process)
O_2		178,202						
N_2		3,214,201						
CO_2		1,001,396						
H_2O		606,687						
SO_2		409						
NO_2		285						
Subtotal	lb/h	5,000,963	0	0	0	0	0	0
TOTAL	lb/h	5,001,020	3,275,778	2,784,411	75,105,834	3,097,367	1,530,729	20,929
Pressure	psia	14.7	560.0	115	55	25	15	15
Temperature	°F	139	1,000	1.50	80	118	80	70
Total Energy	mmBtu/h	835	4,973	2,854	2,854	3,159	73	1

Ultra Supercritical PC and Bituminous Coal - Summary

Summary		
Net Thermal Efficiency	42.7	% HHV
Net Heat Rate (HHV)	8,000	Btu/kWh
Gross Power	543	MW
Internal Power	43	MW
Fuel required	342,863	lb/h
Net Power	500	MW

Ultra Supercritical PC and Bituminous Coal – E&M Balance

Stream	Stream No.	1 Coal Feed	2 Combustion Air	3 HP Steam to T/G	4 Bottom Ash	5 Flue Gas to Filter	6 Ash From Filter	7 Flue Gas to FGD	8 Limestone to FGD	9 Gypsum from FGD
Solids	Units									
Coal, daf	lb/h	270,485	0	0	0	0	0	0	0	0
Sorbent		0	0	0	0	0	0	0	33,055	0
Ash/Slag		34,252	0	0	7,096	28,385	27,985	400	0	0
$CaSO_4.2H_2O$		0	0	0	0	0	0	0	0	49,395
Water		38,126	0	3,691,197	0	0	0	0	0	5,488
Subtotal	lb/h	342,863	0	3,691,197	7,096	28,385	27,985	400	33,055	54,883
Gas										
O_2		0	844,050	0	0	154,467	0	154,467	0	0
N_2		0	2,781,483	0	0	2,785,762	0	2,785,762	0	0
CO_2		0	0	0	0	796,782	0	796,782	0	0
H_2O		0	23,090	0	0	207,287	0	191,191	0	0

Stream	Stream No.	1 Coal Feed	2 Combustion Air	3 HP Steam to T/G	4 Bottom Ash	5 Flue Gas to Filter	6 Ash From Filter	7 Flue Gas to FGD	8 Limestone to FGD	9 Gypsum from FGD
SO_2		0	0	0	0	17,171	0	17,171	0	0
NO_2		0	0	0	0	240	0	240	0	0
Subtotal	lb/h	0	3,648,623	0	0	3,961,709	0	3,945,613	0	0
TOTAL	lb/h	342,863	3,648,623	3,691,197	7,096	3,990,094	27,985	3,946,013	33,055	54,883
Pressure	psia	14.7	14.7	4,515	14.7	13.9	14.7	15.0	14.7	14.7
Temperature	°F	59	59	1,100	2,498	288	287	304	32	86
Total Energy	mmBtu/h	4,002	48	5,413	10	492	15	473	0	1

Stream	Stream No.	10 Flue Gas to Stack	11 Reheat Steam to T/G	12 Turbine Exhaust to Condenser	13 Cooling Water to Condenser	14 Cooling Tower Evaporative Loses	15 Cooling Tower Blowdown	16 Waste Water (from Process)
Solids	Units							
Coal, daf	lb/h	0						
Sorbent		0						
Ash/Slag		48						
$CaSO_4.2H_2O$		0						
Water		0	3,358,989	2,855,141	77,013,663	2,603,555	1,286,649	35,125
Subtotal	lb/h	48	3,358,989	2,855,141	77,013,663	2,603,555	1,286,649	35,125
Gas								
O_2		154,467						
N_2		2,785,762						
CO_2		807,399						
H_2O		362,587						
SO_2		344						
NO_2		240						

Stream	Stream No.	10 Flue Gas to Stack	11 Reheat Steam to T/G	12 Turbine Exhaust to Condenser	13 Cooling Water to Condenser	14 Cooling Tower Evaporative Loses	15 Cooling Tower Blowdown	16 Waste Water (from Process)
Subtotal	lb/h	4,110,799	0	0	0	0	0	0
TOTAL	lb/h	4,110,847	3,358,989	2,855,141	77,013,663	2,603,555	1,286,649	35,125
Pressure	psia	14.7	560.0	115	55	25	15	15
Temperature	°F	128	1,000	1.50	80	118	80	70
Total Energy	mmBtu/h	490	5,099	2,927	2,927	2,656	62	2

Ultra Supercritical PC and Subbituminous Coal - Summary

Summary		
Net Thermal Efficiency	41.9	% HHV
Net Heat Rate (HHV)	8,146	Btu/kWh
Gross Power	543	MW
Internal Power	43	MW
Fuel required	460,227	lb/h
Net Power	500	MW

Ultra Supercritical PC and Subbituminous Coal – E&M Balance

Stream	Stream No.	1 Coal Feed	2 Combustion Air	3 HP Steam To T/G	4 Bottom Ash	5 Flue Gas SDA	6 Lime to SDA	7 SDA Filter Waste	8 Flue Gas To Stack
Solids	Units								
Coal, daf	lb/h	313,323	0	0	0	0	0	0	0
Sorbent		0	0	0	0	0	3,506	0	0
Ash/Slag		20,802	0	0	4,481	17,924	0	17,875	49
$CaSO_4.2H_2O$		0	0	0	0	0	0	10,769	0
Water		126,102	0	3,696,681	0	0	17,531	0	0

Stream	Stream No.	1 Coal Feed	2 Combustion Air	3 HP Steam To T/G	4 Bottom Ash	5 Flue Gas SDA	6 Lime to SDA	7 SDA Filter Waste	8 Flue Gas To Stack
Subtotal	lb/h	460,227	0	3,696,681	4,481	17,924	21,037	28,644	49
Gas									
O_2		0	816,223	0	0	149,374	0	0	149,374
N_2		0	2,689,782	0	0	2,692,795	0	0	2,692,795
CO_2		0	0	0	0	848,425	0	0	849,741
H_2O		0	22,329	0	0	278,655	0	0	417,481
SO_2		0	0	0	0	2,015	0	0	265
NO_2		0	0	0	0	244	0	0	244
Subtotal	lb/h	0	3,528,333	0	0	3,971,509	0	0	4,109,899
TOTAL	lb/h	460,227	3,528,333	3,696,681	4,481	3,989,433	21,037	28,644	4,109,948
Pressure	psia	14.7	14.7	4,515	14.7	13.9	14.7	14.7	14.7
Temperature	°F	59	59	1,100	2,498	256	32	86	132
Total Energy	mmBtu/h	4,076	50	5,421	9	576	0	0	569

Stream	Stream No.	9 Reheat Steam To T/G	10 Turbine Exhaust to Condenser	11 Cooling Water To Condenser	12 Cooling Tower Evaporative Loses	13 Cooling Tower Blowdown	14 Waste Water (from Process)
Solids	Units						
Coal, daf	lb/h						
Sorbent							
Ash/Slag							
$CaSO_4.2H_2O$							

Stream	Stream No.	9 Reheat Steam To T/G	10 Turbine Exhaust to Condenser	11 Cooling Water To Condenser	12 Cooling Tower Evaporative Loses	13 Cooling Tower Blowdown	14 Waste Water (from Process)
Water		3,363,980	2,859,383	77,128,092	2,651,199	1,310,061	6,461
Subtotal	lb/h	3,363,980	2,859,383	77,128,092	2,651,199	1,310,061	6,461
Gas							
O_2							
N_2							
CO_2							
H_2O							
SO_2							
NO_2							
Subtotal	lb/h	0	0	0	0	0	0
TOTAL	lb/h	3,363,980	2,859,383	77,128,092	2,651,199	1,310,061	6,461
Pressure	psia	560.0	115	55	25	15	15
Temperature	°F	1,000	1.50	80	118	80	70
Total Energy	mmBtu/h	5,107	2,931	2,931	2,704	63	0

Ultra Supercritical PC and Lignite Coal - Summary

Summary		
Net Thermal Efficiency	37.6	% HHV
Net Heat Rate (HHV)	9,065	Btu/kWh
Gross Power	546	MW
Internal Power	46	MW
Fuel required	720,849	lb/h
Net Power	500	MW

Ultra Supercritical PC and Lignite Coal – E&M Balance

Stream	Stream No.	1 Coal Feed	2 Combustion Air	3 HP Steam to T/G	4 Bottom Ash	5 Flue Gas to Filter	6 Ash From Filter	7 Flue Gas to FGD	8 Limestone to FGD	9 Gypsum from FGD
Solids	Units									
Coal, daf	lb/h	366,191	0	0	0	0	0	0	0	0
Sorbent		0	0	0	0	0	0	0	16,022	0
Ash/Slag		129,465	0	0	26,273	105,093	104,660	453	0	0
$CaSO_4.2H_2O$		0	0	0	0	0	0	0	0	28,066
Water		225,193	0	3,715,590	0	0	0	0	0	3,118
Subtotal	lb/h	720,849	0	3,715,590	26,273	105,093	104,660	453	16,022	31,184
Gas										

Stream	Stream No.	1 Coal Feed	2 Combustion Air	3 HP Steam to T/G	4 Bottom Ash	5 Flue Gas to Filter	6 Ash From Filter	7 Flue Gas to FGD	8 Limestone to FGD	9 Gypsum from FGD
O_2		0	932,749	0	0	170,699	0	170,699	0	0
N_2		0	3,073,783	0	0	3,078,867	0	3,078,867	0	0
CO_2		0	0	0	0	953,222	0	953,222	0	0
H_2O		0	25,517	0	0	415,559	0	396,467	0	0
SO_2		0	0	0	0	9,210	0	9,210	0	0
NO_2		0	0	0	0	272	0	272	0	0
Subtotal	lb/h	0	4,032,049	0	0	4,627,829	0	4,608,736	0	0
TOTAL	lb/h	720,849	4,032,049	3,715,590	26,273	4,732,921	104,660	4,609,190	16,022	31,184
Pressure	psia	14.7	14.7	4,515	14.7	13.9	14.7	15.0	14.7	14.7
Temperature	°F	59	59	1,100	2,498	279	278	295	32	86
Total Energy	mmBtu/h	4,538	56	5,448	31	805	28	772	0	1

Stream	Stream No.	10 Flue Gas to Stack	11 Reheat Steam to T/G	12 Turbine Exhaust to Condenser	13 Cooling Water to Condenser	14 Cooling Tower Evaporative Loses	15 Cooling Tower Blowdown	16 Waste Water (from Process)
Solids	Units							
Coal, daf	lb/h	0						
Sorbent		0						
Ash/Slag		55						
$CaSO_4.2H_2O$		0						
Water		0	3,381,187	2,874,009	77,522,608	2,966,345	1,465,973	19,958
Subtotal	lb/h	55	3,381,187	2,874,009	77,522,608	2,966,345	1,465,973	19,958
Gas								
O_2		170,699						
N_2		3,078,867						
CO_2		959,232						

Stream	Stream No.	10 Flue Gas to Stack	11 Reheat Steam to T/G	12 Turbine Exhaust to Condenser	13 Cooling Water to Condenser	14 Cooling Tower Evaporative Loses	15 Cooling Tower Blowdown	16 Waste Water (from Process)
H_2O		581,479						
SO_2		390						
NO_2		272						
Subtotal	lb/h	4,790,730	0	0	0	0	0	0
TOTAL	lb/h	4,790,785	3,381,187	2,874,009	77,522,608	2,966,345	1,465,973	19,958
Pressure	Psia	14.7	560.0	115	55	25	15	15
Temperature	°F	139	1,000	1.50	80	118	80	70
Total Energy	mmBtu/h	794	5,133	2,946	2,946	3,026	71	1

Notes on waste Streams:

Solid Waste:
The solid waste streams from a PC boiler are: furnace bottom ash, fly ash and gypsum or other waste products resulting from the sulfur capture. The fly ash is captured by fabric filters. The wet FGD process generates gypsum. In the dry FGD process, the calcium waste is captured in the fabric filter with fly ash.

Liquid Waste:
Liquid waste is primarily from boiler blowdown in drum type subcritical boilers, and from cooling tower blowdown. In addition, the wet FGD process may generate a bleed waste stream. This waste stream is reported as part of the total waste water discharge. The dry process does not generate a wastewater stream during the sulfur capture process.

Make-Up Water:
Make-up water includes waste water discharge, as well as losses in the cooling tower.

ENERGY CENTER OF WISCONSIN

IGCC Engineering and Permitting Issues Summaries

Clean Coal Study Group

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Part 1 – IGCC Engineering Issues Summary –

The purpose of this briefing paper is to summarize engineering issues associated with the commercial application of coal-fueled integrated gasification combined cycle (IGCC) systems for electricity generation in Wisconsin.

The key questions identified by the Study Group and addressed in this paper are:

1. *Is IGCC technology ready for commercial application?*
2. *How do the operational characteristics and construction timeframe of an IGCC plant compare to super critical pulverized coal (SCPC)?*
3. *How does coal type affect IGCC's operational characteristics?*
4. *Does IGCC's fuel flexibility offer additional reliability benefits?*

In addition to addressing these questions, this paper also provides further information on current engineering efforts to improve performance and profitability.

1. Is IGCC technology ready for commercial application?

Coal-fired IGCC for energy generation is on poised for commercial application. The current round of proposed plants are expected to provide vital confirmation of predicted capital costs that will supplement technical demonstrations of feasibility from existing gasification plants.[1] There is tremendous activity surrounding IGCC from major players such as GE, Bechtel, Conoco Philips, Shell, the U.S. DOE, EPRI and GTI.

EPRI is spearheading an important commercialization effort known as the "Coal Fleet of Tomorrow." The aim of the Coal Fleet initiative is "to ensure competitive commercial offerings by 2015 to 2020."[2] This is being done through an industry consortium which will collectively address the barriers to commercialization for all advanced coal technologies. It is significant to note that Coal Fleet is dedicating 90% of its initial effort to IGCC with the remaining 10% going to other technologies such as ultra supercritical pulverized coal.

According to the Coal Fleet Program Summary, "advanced coal technologies cannot reach commercial maturity until they have been proven in full-scale operation, under 'real world' conditions, for a sufficient time period to assure expectations of performance and reliability. This is essential to convince prospective investors that costs and risks are sufficiently understood."[3] Towards this end, major players are designing and planning for commercial scale demonstrations. For example, under a partnership with Bechtel, GE expects to complete a 630MW, IGCC reference plant design by Q4 of 2006. By producing a standard reference plant design GE expects to be able to offer a structured product, with lower capital expenditure, shorter cycle time and performance guarantees.[4]

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[1] Kosstrin, Herbert M., "Tomorrow's Clean Coal Plants, Today," *Public Power*, Vol 64 No 2, March-April 2006.
[2] http://www.epri.com/portfolio/product.aspx?id=1295
[3] http://www.epriweb.com/public/corp_CoalFleet.pdf
[4] Lowe, Edward, "GE's Gasification Developments," Gasification Technologies Council, October, 2005 http://www.gasification.org/

There are currently two large scale IGCC projects under serious consideration. Both projects have been the subject of discussion and pre-planning efforts since at least 2004.[5] GE, Bechtel and American Electric Power (AEP) are currently furthest along in the process with three potential locations identified in Meigs County, Ohio, Lewis County, Kentucky, and Mason County, West Virginia. All three sites are located along the Ohio River. AEP hopes to begin construction in 2006 with completion targeted for 2010. Cinergy is also considering an IGCC plant in Indiana or Kentucky and has signed a letter of intent with GE and Bechtel for feasibility studies. [6,7,8]

Gasification itself is a fairly mature process. However, most gasifiers are used to produce Fischer Tropsch liquids and chemicals from coal and petroleum rather than power through IGCC.[9] The problem being that based purely on cost of electricity (COE), IGCC is not competitive with traditional pulverized coal or natural gas. Similarly, in the future, IGCC is not expected to be the lowest cost solution without the imposition of significant additional emissions restrictions. As additional emissions restrictions are imposed on electricity generators, IGCC is expected to become the lowest cost solution – especially if carbon capture and sequestration is required. The remainder of this paper will consider technical aspects of IGCC, including advantages, challenges and ongoing development projects.

2a. How do the operational characteristics of an IGCC plant compare to super critical pulverized coal (SCPC)?

One significant advantage of IGCC is its relatively high efficiency, which is derived from the "combined cycle" portion of the process. IGCC is expected to yield higher electricity production efficiency than any other coal technology for the foreseeable future. This fact alone makes IGCC attractive from an emissions standpoint. In addition to the high efficiency, the need to clean the syngas prior to combustion in a turbine results in an extremely clean exhaust stream. IGCC also results in significantly lower water consumption and solids production. Table 1 summarizes emissions profiles for IGCC compared to pulverized coal. GE estimates that if super critical pulverized coal were required to achieve the same emissions levels as an IGCC plant, IGCC would achieve cost parity.[10] However, the real advantage for IGCC comes in when carbon capture and sequestration (CCS) are considered.

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[5] "Gasification – World Survey Results," U.S. DOE, Office of Fossil Energy, National Energy Technology Laboratory, 2004 http://www.netl.doe.gov/publications/brochures/pdfs/Gasification_Brochure.pdf

[6] http://www.ge.com/stories/en/20385.html?category=Product_Business

[7] http://www.aep.com/newsroom/newsreleases/default.asp?dbcommand=DisplayRelease&ID=1190

[8] "AEP asks PJM for Transmission Interconnect Study," Platts T&D, 3/7/2005 http://www.platts.com/Magazines/Platts%20T&D/News%20Archive/2005/030705_1.xml

[9] http://www.netl.doe.gov/publications/brochures/pdfs/Gasification_Brochure.pdf

[10] Rigdon, Robert; Schmoe, Lee, "The IGCC Reference Plant," Gasification Technologies Council, October, 2005 - http://www.gasification.org/

Table 1: Comparison of emissions for IGCC versus a conventional pulverized coal plant with emissions controls.[11]

	IGCC	Pulverized Coal
Sulfur Dioxide (lb/MBTU)	0.08	0.3
Nitrogen Oxide (lb/MBTU)	0.06	0.09
Particulate Matter (lb/MBTU)	0.06	0.3
Water Consumption (gal/MWh)	440	640
Total Solids Generated (lb/MWh)	120	250

The reason for IGCC's relative advantage in CCS is the concentration of the exhaust stream. The CO2 concentration in natural gas exhaust is around 4%. For pulverized coal it increases to around 15%. For IGCC, carbon separation can be done prior to syngas combustion where CO_2 concentrations can be 35-40%.[12]

A study conducted by MIT shows that the cost per tonne of avoided CO_2 emissions is dramatically lower for IGCC compared to natural gas combined cycle (NGCC) or pulverized coal. However, because of the extremely high efficiency of NGCC and resulting low CO_2 emissions, the actual added cost of electricity for IGCC and NGCC is quite similar. These results are summarized in Table 2. So, the ultimate economic viability of IGCC depends on two main components: increasingly stringent emissions requirements (particularly CO2) and high natural gas prices.[13]

Table 2: Cost of carbon capture from various generation technologies.[14]

	IGCC	Pulverized Coal	NGCC
CO2 Created (kg/kWh)	6.64	7.66	3.37
Cost of Avoided CO_2 ($/tonne)	18	32	41
Incremental COE (cents / kWh)	1.04	2.16	1.23

One persistent concern with IGCC systems is availability or reliability which has been demonstrated to be a critical factor in achieving an acceptable return on investment.[15] Gasifier availability numbers for several IGCC projects are listed in Table 3. Future

[11] Pashos, Kay, "IGCC – An Important Part of Our Future Generation Mix," Gasification Technologies Council, October, 2005 - http://www.gasification.org/
[12] Alvey, Jennifer, "The Carbon Conundrum," Fortnightly Magazine, August, 2003 - http://www.pur.com/pubs/4229.cfm
[13] Narula, Ram, "IGCC vs. SCPC: Battle of Technologies II," Gasification Technologies Conference, October 2005 - http://www.gasification.org/
[14] David, Jeremy; Herzog, Howard, "The Cost of Carbon Capture," MIT – http://www.netl.doe.gov/publications/proceedings/01/carbon_seq_wksp/David-Herzog.pdf
[15] Amick, P., et al, "A Large Coal IGCC Power Plant," Bechtel Technical Paper, September, 2002 http://www.bechtel.com/PDF/BIP/22008.pdf

IGCC plants are expected to address this reliability question in two ways. First, gasifier improvements are expected to increase availability. Second, most commercial applications are expected to include a spare gasification train. This is currently considered a necessity for achieving "syngas availability" of >90%.[16]

Table 3: Reported gasifier availability rates for several demonstration IGCC plants.[17]

Location	Puertollano, Spain	Elcogas	Nuon	Wabash River, IN	Polk Power Station, FL
Gasifier Availability	76%	69%	82%	79%	82%

2b. How does the construction timeframe of an IGCC plant compare to super critical pulverized coal (SCPC)?

There is much speculation in the literature about construction cost and timeline for IGCC and other advanced coal technologies. Unfortunately, there is little actual experience and this is one of the key risk factors which has been identified,[18] and is being addressed by, the Coal Fleet of Tomorrow initiative. The GE/Bechtel reference plant design mentioned above is one example of what is being done to mitigate this uncertainty. However, standardization of design and streamlining of permitting processes are a common theme for major power projects across the board and IGCC will need to utilize these advanced design and construction techniques just to keep up.

A survey of coal technologies conducted by the World Bank found that construction of a traditional pulverized coal plant requires 38-58 months to complete. IGCC and Air Fluidized Bed Combustion plants were both estimated to have similar time frames. The study did find that Pressurized Fluidized Bed Combustion plants had the potential for shorter construction times (24-48 months) due to the potential for modular design and construction.[19] Alternatively, another study by the U.S. DOE concluded that IGCC and circulating pressurized fluidized-bed combustors (CPFBC) should be expected to have longer than average construction lead times.[20]

In terms of actual "on the ground" experience, both the Wabash River Repowering project and the Polk Power Station greenfield project were completed with 2 years of physical construction time. The Wabash River plant was retrofitted between July of 1993

[16] Holt, N., "Coal-based IGCC Plants – Recent Operating Experience and Lessons Learned," Gasification Technologies Conference, Washington, DC, October, 2004 http://www.gasification.org/Docs/2004_Papers/22HOLT.pdf

[17] Holt, N., "Coal-based IGCC Plants – Recent Operating Experience and Lessons Learned," Gasification Technologies Conference, Washington, DC, October, 2004 http://www.gasification.org/Docs/2004_Papers/22HOLT.pdf

[18] Nautilus Institute, "IGCC in China," February 1999, - http://www.nautilus.org/archives/papers/energy/NIIGCCESENAY3.pdf

[19] Tavoulareas, E.S., Charpentier, J.P, World Bank Technical Paper No. 286, "Clean Coal Technologies for Developing Countries," July 1995 http://www.worldbank.org/html/fpd/em/power/EA/mitigatn/thermpow.stm#top

[20] U.S. DOE, Office of Fossil Energy, "Market-Based Advanced Coal Power Systems – Final Report," May 1999 - http://www.fe.doe.gov/programs/powersystems/publications/MarketBasedPowerSystems/marketbased_systems_report.pdf

and November of 1995.[21] The Polk Power Station was constructed between November of 1994 and September of 1996.[22]

3. How does coal type affect IGCC's operational characteristics?

Another frequently touted advantage of IGCC is fuel flexibility. The technical and economic performance of IGCC depends more strongly on feedstock quality than pulverized coal.[23] In the cost critical commodity market for electricity, IGCC will most likely require optimum performance and therefore consistently high quality fuel for the gasifier. Table 4 details several IGCC plants which are currently under consideration. The two plants which are furthest along in the development process are based in the Ohio River valley with easy access to high grade coals.[24]

Table 4: IGCC projects currently under consideration in the U.S.

Project	Details
American Electric Power	AEP has initiated interconnection studies with PJM for consideration of one or two 600MW, GE IGCC power plants. AEP is still evaluating several potential locations in the Ohio River Valley.[25]
Cinergy	"Cinergy signed a letter of intent with General Electric and Bechtel for a feasibility study for an IGCC plant, most likely in Indiana or Kentucky. A Cinergy IGCC facility probably would be in the range of 500 MW to 800 MW. The company would like to have it in commercial operation around the end of the decade."[26]
Mesaba Energy Project	Excelsior Energy has plans for a 600MW ConocoPhillips E-Gas plant in Minnesota. Expected to begin operation in 2010 the project will utilize bituminous and sub-bituminous coals as well as pet coke.[27]
Energy Northwest	Energy Northwest is working on site selection for a 600MW IGCC facility in Washington state.[28]
Stanton Energy Center	This is a joint development project for a 235MW IGCC plant between the DOE and the Southern Company. The project is slated for ground breaking in 2007 and operation in 2010.[29]
Indian River Plant	"NRG Energy Inc. could put forward plans in the first half of 2006 to repower an existing generating unit in Connecticut, Delaware, Maryland or New York with coal gasification technology."[30]

[21] "The Wabash River Coal Gasification Repowering Project," National Energy Technology Lab Topical Report #7, November 1996 http://www.netl.doe.gov/publications/others/topicals/topical7.pdf

[22] "Polk Power Station, IGCC Operation – Lessons Learned," DOE Clean Coal Roundtable, July 2004 http://www.climatevision.gov/pdfs/coal_roundtable/hornick.pdf

[23] Dalton, Stu, "Cost Comparison IGCC and Advanced Coal," presented at the Roundtable on Deploying Advanced Clean Coal Plants, July 2004 http://www.climatevision.gov/pdfs/coal_roundtable/dalton.pdf

[24] "Gasification – World Survey Results," U.S. DOE, Office of Fossil Energy, National Energy Technology Laboratory, 2004 http://www.netl.doe.gov/publications/brochures/pdfs/Gasification_Brochure.pdf

[25] http://www.platts.com/Magazines/Platts%20T&D/News%20Archive/2005/030705_1.xml

[26] http://www.platts.com/Magazines/Platts%20T&D/News%20Archive/2005/030705_1.xml

[27] http://www.climatevision.gov/pdfs/coal_roundtable/jorgensen.pdf

[28] http://www.energy-northwest.com/downloads/igcc/IGCC%20Newsletter%200509.pdf

[29] http://www.ouc.com/news/arch/20041021-cleancoal_proj.htm

[30] http://www.snl.com/InteractiveX/article.aspx?CDID=A-2268341-13154

Table 5 summarizes the estimated heat rate and capital cost for an IGCC plant when various coals are used. Due to the fact that emissions controls occur in the gas phase, prior to combustion, emissions performance is largely independent of gasifier feedstock.

Table 5: Engineering, procurement and construction cost estimates for a ConcoPhillips E Gas technology using different fuels.[31]

	Engineering, Procurement and Construction Cost ($/kW)	Approximate Heating Value (BTU/lb)
Bituminous Coal (Pitts #8)	1,140	13,100
Petroleum Coke	1,160	13,000
Bituminous Coal (Ill #6)	1,240	11,000
Sub-Bituminous Coal (Powder River Basin)	1,410	8,200
Lignite Coal	1,580	7,500

4. Does IGCC's fuel flexibility offer additional reliability benefits?

Due to the economic sensitivity to coal type it is unlikely that IGCC plants will be operated with a wide variety of feedstocks. In the event of a coal supply interruption, IGCC could be operated using suboptimal feedstocks. However, it does not appear that this would occur in such a way as to provide a competitive advantage to IGCC over other technologies.

However, IGCC units are fuel flexible in a secondary sense as well. The overall plant reliability and capacity factor can be substantially improved by maintaining the flexibility to run the combined cycle power block with natural gas. When the gasifier is down for maintenance, the power block remains operational. The IGCC plant in Puertollano, Spain and the Polk Power Station in Florida have reported power production availability of >93% by supplementing with natural gas despite gasifier availabilities of 76% and 82% respectively.[32]

Continuing Engineering Development and Performance Improvement

IGCC is an immature technology when compared to NGCC and pulverized coal. As a result, significant performance improvements and capital cost reductions are expected for IGCC in the coming years. The rate of improvement is expected to significantly outpace advances in the more mature technologies against which IGCC is competing. Figure 1 shows the configuration of the Wabash River Plant and provides an illustration of the major components of an IGCC plant. Several of these components are the focus of active research and development and are discussed below.

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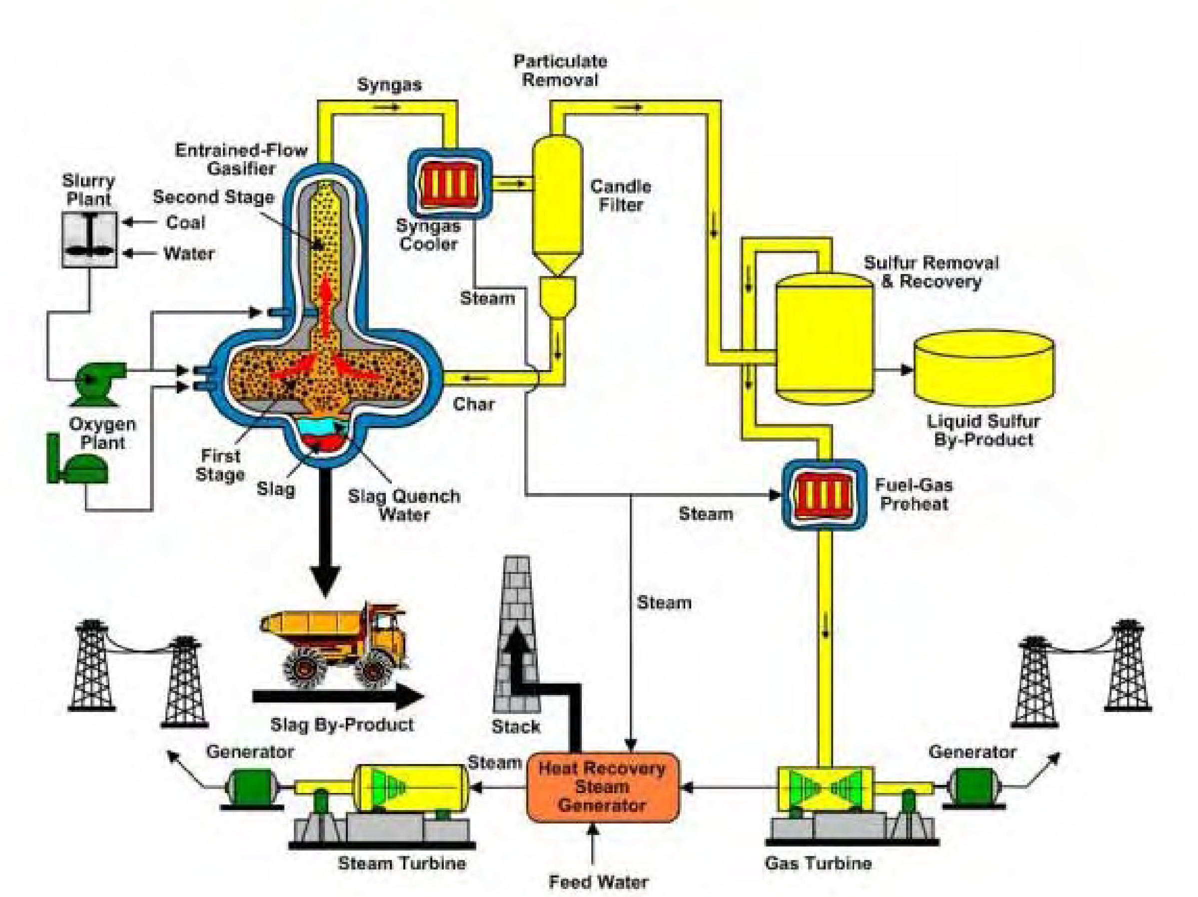
[31] Holt, N., Booras, G., "A Summary of Recent IGCC Studies of CO2 Capture for Sequestration," The Gasification Technologies Conference, San Francisco, CA, October, 2003

[32] Holt, N., "Coal-based IGCC Plants – Recent Operating Experience and Lessons Learned," Gasification Technologies Conference, Washington, DC, October, 2004 http://www.gasification.org/Docs/2004_Papers/22HOLT.pdf

Figure 1: Schematic of the Wabash River Repowering Project plant.[33]



Coal Feed

The Wabash plant and other coal gasifiers currently use a coal and water slurry system to deliver coal to the gasifier. Significant efforts are being made to develop viable dry feed systems. The potential advantages of a dry feed mechanism include reduced water use, reduced capital cost and reduced maintenance requirements. Methods of dry delivery include lock hopper systems and solids pumps.

One of the primary challenges associated with dry feed systems is the ability to deliver the coal at an elevated pressure. Lock hoppers accomplish this by passing the coal through staged load locks that enable the pressure to be increased in stages. The solid pumps are more elegant and allow continuous feed of the coal. A recent paper from Stamet, Inc. reported the successful continuous delivery of pulverized coal at a pressure of more than 500psi. Another advantage of Stamet's "Posimetric" dry feed pump is that it requires significantly less make up gas than lock hopper systems, therefore reducing the amount of pure oxygen required.

[33] http://www.clean-energy.us/illustrations/schematic_wabash_igcc.htm

Additional development of the dry pump is currently underway with the goals of achieving a 1000psi feed pressure and integrating a commercial scale unit at the Power Systems Development Facility in Wilsonville, AL.[34]

Oxygen Plant

Gasification is done in a precisely controlled atmosphere which allows the coal (or other feedstock material) to react without combusting. To accomplish this, most gasifiers are "oxygen blown", meaning that nearly pure oxygen is fed into the gasifier unit. Oxygen separation from the atmosphere has typically been accomplished through a cryogenic distillation process. Air is cooled until the various gases condense to liquids and can be separated. This is an expensive and energy intensive process which can account for as much as 15% of the capital costs and reduce the overall efficiency of the IGCC plant.

The primary effort in this area is to develop an Ion Transport Membrane (ITM) system which will produce oxygen for approximately 2/3 the cost of conventional cryogenic systems. Successful integration of an ITM oxygen system is expected to improve overall plant efficiency by 2.2% and reduce the total plant capital cost by 7%.[35]

The ITM development project was started in 1999 and is being led by Air Products. Phase 1 of the project has been completed and demonstrated 0.1 tons per day of oxygen production. Phase 2 is currently underway with the goal of demonstrating 1-5 tons per day of oxygen production. The final phase will aim to demonstrate 25-150 tons per day of oxygen production and is scheduled to be completed in 2008. The Department of Energy's FutureGen project (2012) is expected to require 500-2000 tons per day of oxygen.[36]

Gasification

There are numerous projects underway to improve the operation of gasifiers which are the central component of an IGCC plant. These projects range from materials improvements of refractory gasifier liners and metal component coatings to improved flame monitoring equipment. Work is also underway to develop and evaluate entirely new gasifier designs. For example, Rocketdyne has efforts underway to adapt its rocket engines for low cost, high efficiency coal gasification.[37] The Power Systems Development Facility has been in operation since 1990 and is the main facility for demonstration of advanced coal configurations and components.[38]

As mentioned above, one of the important gasifier efforts focuses on improvements to refractory components. These components line and protect the inside of the gasifier chamber and are subject to harsh chemical and high temperature environments.

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[34] Saunders, Timothy, Aldred, Derek, "Successful Continuous Injection of Coal into Gasification and PFBC System Operating Pressures Exceeding 500psi – DOE Funded Program Results," October, 2005 http://www.gasification.org/Docs/2005_Papers/44SAUN%20Paper.pdf

[35] http://www.netl.doe.gov/technologies/coalpower/gasification/projects/gas-sep/O2/o2-42469.html

[36] Armstrong, Phillip, et al., "ITM Oxygen: The New Oxygen Supply for the New IGCC Market," Gasification Technologies 2005, http://www.gasification.org/

[37] http://www.netl.doe.gov/technologies/coalpower/gasification/projects/adv-gas/adv-design/ad42237.html

[38] "Clean Coal Today," U.S. DOE, Office of Fossil Energy, DOE/FE-0215P-41, Fall 2000 http://www.netl.doe.gov/technologies/coalpower/cctc/newsletter/documents/00_fall.pdf

Improving the robustness of these refractory materials and simplifying the change out procedures are critical to improving the up-time of IGCC units.[39]

Syngas Clean-up

One of the major goals for improving the IGCC process is to enable hot syngas clean-up. The current standard process takes the syngas from its formation temperature of 2100-2700°F and cools it in several stages. At the Wabash River Plant the syngas is ultimately cooled to ambient temperature prior to desulfurization through hydrolysis. The syngas is then reheated prior to combustion in the turbine.[40]

Advanced desulfurization methods use zinc and sodium based sorbents injected in the gas stream to clean the gas. This has been demonstrated at "warm" gas temperatures of 550°F.[41]

Gas Turbine

According to a paper on design and integration of IGCC power plant facilities prepared by Bechtel, the gas turbine is the critical component for optimizing overall plant performance. Critical considerations include: integration with the high pressure steam generation from exhaust gases, air extraction integration between the gas turbine and the air separation unit, NOx control, gas turbine power augmentation and overall optimization of the gas turbine for use with syngas.[42,43] The U.S. DOE has several programs in place aimed at near, mid and long-term turbine development objectives extending out to the year 2020.[44]

Conclusion

IGCC is ready for large scale demonstration and early adopter investment (supplemented by significant government assistance). In order to move from this stage to full commercial viability, IGCC is dependent on four critical developments. These are:

- Continued technological advances to improve efficiency and reduce capital cost
- Continued tightening of emissions requirements – most critically carbon emissions
- Continued high cost of natural gas
- Successful completion of large scale demonstration facilities to provide construction and operating experience and reduce investment risk.

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[39] http://www.netl.doe.gov/technologies/coalpower/gasification/projects/adv-gas/materials/materials/matAA010B.html

[40] "The Wabash River Coal Gasification Repowering Project," National Energy Technology Lab Topical Report #7, November 1996 http://www.netl.doe.gov/publications/others/topicals/topical7.pdf

[41] http://www.netl.doe.gov/technologies/coalpower/gasification/projects/gas-clean/adv-clean/ac40674.html

[42] Geosits, R.F., Schmoe, L.A., "IGCC – The Challenges of Integration," GT2005 ASME Turbo Expo 2005, June 2005 http://www.bechtel.com/PDF/BIP/35478.pdf

[43] http://www.gepower.com/prod_serv/products/tech_docs/en/downloads/ger4207.pdf

[44] http://www.netl.doe.gov/technologies/coalpower/turbines/goals.html

Part 2 – IGCC Permitting Policy Issues Summary – Clean Coal Study Group – March 2006

The purpose of this briefing paper is to highlight permitting issues associated with the commercial installation of coal-fueled IGCC systems for electricity generation in Wisconsin. The Clean Coal Study Group identified the following guiding questions about policy issues related to IGCC permitting.

1. *Are there any barriers to permitting an IGCC unit in the state?*
2. *What, if any, policy changes might be needed to permit an IGCC unit in Wisconsin?*
3. *What can we learn from other states?*
4. *Are there regulatory options for risk-sharing given that IGCC is a newer technology?*

This document is organized along the lines of these questions to directly address the needs of the group.

1. Are there any barriers to permitting an IGCC unit in the state?

IGCC facilities face many of the same permitting barriers that more-established fossil fuel combustion technologies must face. This section focuses on two barriers that are unique to, or are more pronounced with IGCC facilities. These are:

- IGCC status as a pre-commercial technology for energy generation,
- Lack of requirements for the strict emissions controls of which IGCC is capable.

Pre-Commercial Technology

Probably the largest hurdle for IGCC technology is the fact that it is not yet fully commercially demonstrated for electricity generation. This situation creates a number of difficulties. First, state permitting agencies may not have sufficient information on these systems to allow routine and timely permitting. For instance, composition and proper handling and treatment of production byproducts such as gasifier slag may not be well known at the point of permitting. Furthermore, should CO_2 emissions become regulated, the permanence, efficacy and practicality of sequestration practices such as deep geologic sequestration and enhanced oil recovery require further study. This can translate into costly delays in the permitting process. While the scant experiences with permitting for IGCC projects thus far includes some signs that environmental regulators view the systems positively, due largely to the favorable emissions profile for the technology,[45] permitting agencies and applicants alike would benefit greatly by having dependable, unbiased information resources and personnel to help guide their process.

Another possible new-technology related permitting issue is that environmental performance and operational reliability may not be as consistent for IGCC facilities as that of more-established technologies during the early stages of implementation and

[45] Talend, Don, "On the Clean Cutting Edge: Planned Illinois plant should serve as a reference for coal gasification benefits for future coal facilities," *Distributed Energy: The Journal for Onsite Power Solutions*, November/December 2005.

operation. Deployment of the first commercial scale IGCC systems using coal for energy generation will require a period of "shakedown" in which the technology and operational practices are tuned and refined before steady-state operation begins.

The complexity and flexibility of an IGCC facility can also work against it during permitting. A National Association of Regulatory Utility Commissioners report describes the licensing process for IGCC power plants as being far more complex than conventional coal plants and calls it a "major challenge in IGCC deployment".[46] Under current requirements, IGCC power plants may require licensing as electricity generation units, as syngas facilities, and as co-production plants. David Schwartz, of the ERORA Group, a private developer working on the Taylorville IGCC facility in Central Illinois, concurs that the most difficult part of the permitting process is getting the facility to be viewed as one facility rather than three separate components.[47]

Finally, the higher cost associated with IGCC plants relative to other advanced coal technologies (a cost differential that is expected to narrow as more plants are installed) can make it difficult to obtain a Certificate of Public Convenience and Necessity. Evaluation tools used by the utility commissions may not attribute sufficient value to the positive traits of IGCC to offset these higher costs.

Lack of Incentives to Go Beyond Compliance

One of the strengths of IGCC systems for electricity generation using coal is their potential for emissions control including CO_2 capture for sequestration. Current environmental permitting practices negatively affect IGCC systems in a backhanded way by not requiring the degree of control of which this technology is uniquely suited. Therefore, evaluation of IGCC systems versus other advanced coal technologies will leave this important trait off the balance sheet, putting IGCC at a disadvantage. Incentives to go beyond compliance such as tradable emissions credits can give IGCC systems some monetary benefit for their low emissions and make them compare more favorably financially.

2. What, if any, policy changes might be needed to permit an IGCC unit in Wisconsin?

Based on previous research, policy changes that would simplify permitting of an IGCC unit in Wisconsin include:

- An expedited process to develop a single set of standards specifically for siting and permitting IGCC plants including co-production processes.
- Development of a Memoranda of Understanding specifying compatible regional standards to address air shed issues associated with IGCC permitting.
- Set IGCC as the BACT of coal power plants

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[46] National Association of Regulatory Utility Commissions, *An Analysis of the Institutional Challenges to Commercialization and Deployment of IGCC Technology in the U.S. Electric Industry: Recommended Policy, Regulatory, Executive and Legislative Initiatives*, March 2004, DOE/NARUC Partnership for Advanced Clean Coal Technology, prepared by Global-Change Associates.
[47] Talend D, 2005.

An Expedited Process for Permitting

Currently an IGCC plant is subject to multiple permitting processes because it is treated as both a chemical plant and a power plant. The gasifier, the gas turbine and the co-production unit operations must obtain separate and distinct operating permits, which greatly complicates and slows the permitting process. Therefore, state government development of a single set of standards specifically for siting and permitting IGCC plants, including co-production processes, would be beneficial.

In addition, although the flexibility of feedstocks for IGCC is theoretically a benefit due to financial stability because of diversification options, it also creates complications in siting and permitting of IGCC plants. This is because permit-based requirements for material handling, allowable emissions and operator training varies based on the feedstock.

Memoranda of Understanding to Address Air Shed Issues

The states could develop Memoranda of Understanding specifying compatible regional standards to address air shed issues associated with IGCC permitting. The transitional state-by-state changes in the electric utility industry have resulted in a lack of regional planning. This lack of regional planning has resulted in short-term and incremental investments in energy such as NGCC rather than in investments in systems that are economically sustainable in the long-term.

Setting IGCC as the BACT of Coal Power Plants

The New Source Review (NSR) process requires that a company proposing to build a major new emissions source, or to make major modifications on an existing source, act to minimize air pollution emissions by changing the process and/or installing air pollution control equipment. Sources going through NSR in attainment areas (those not designated by the US EPA as being in non-attainment for the criteria pollutant(s) in question) must identify and install the Best Available Control Technology (BACT). The BACT process includes 5 steps: 1) identify all control technologies, 2) eliminate technically infeasible options, 3) rank remaining control technologies by control effectiveness, 4) evaluate most effective controls and document results, and 5) select BACT. In December of 2005 the US EPA decided that IGCC need not be considered under a Clean Air Act BACT analysis for proposed pulverized coal-fueled electricity generating facilities. However, contrary to the federal decision, specific states including: California, New Mexico, Illinois, and Montana decided the BACT for coal plants is now IGCC. For those states when a power company decides to invest in a new coal power plant they must use IGCC or a technology that is better than IGCC in terms of meeting emission standards and requirements.

3. What can we learn from other states?

The National Association of Regulatory Utility Commissioners, the National Association of State Energy Officials, and the Environmental Council of States developed a survey to collect and describe different State approaches and/or incentives for improved environmental performance of fossil-fuel based electricity generators. The survey data provides examples of regulatory options to encourage utilities to upgrade existing baseload generation facilities through incentives, mandates and rate cases. Policy tools that the report listed in states to advance the development of IGCC can be categorized as: air pollution regulations, cost recovery rules, demand-side management, and financing mechanisms.[48] The main conclusions from their survey are:

- More widespread and consistent incentives may encourage increased regulatory certainty, enabling utilities to initiate widespread environmental upgrades.
- Most states do not have mandated financial or regulatory incentives for base-load environmental upgrades and this contributes to lack of regulatory certainty and high implementation costs.

There are currently six IGCC plants in the United States. Two of these are under 150MWe (Coolwater, Frontier) and four are 150-325MWe (Wabash, Dow, Polk, Delaware). However, both Coolwater and Dow are decommissioned. According Jim Falsetti of Process Energy Systems there are currently 16 proposed IGCC projects located in Florida, Idaho, Illinois, Indiana, Kentucky, Minnesota, Ohio, Oklahoma, Wyoming, and Pennsylvania, ranging in size from 41 MWe to 2400 MWe. Although there are many factors that influence the decision to invest in an IGCC plant, state policies can play a role. For the listed states the policies they have implemented include:

A. Air pollution regulations where utilities are allowed to improve cash flow by including pollution control equipment as construction work in progress in the rate base (IN)
B. A cost-sharing program to reduce GHG emissions (OH)
C. A cost-recovery program (IN)
D. An environmental surcharge which provides for the current recovery of the costs of complying with the Clean Air Act and other environmental requirements (KY)
E. Loans for development of alternative energy technologies (PA)
F. Rate making treatments (IN, PA)
G. Set-asides for certain technologies such as alternative or advanced energy portfolios (PA)
H. Expedited depreciation of IGCC plants (IN)

4. Are there regulatory options for risk-sharing given that IGCC is a newer technology?

Two options for state risk-sharing in developing, installing and operating IGCC systems are summarized below.

[48] National Association of Regulatory Utility Commissioners, "A Survey of State Incentives Encouraging Improved Environmental Performance of Base-Load Electric Generation Facilities: Policies and Regulatory Initiatives." Publication available at: http://www.naruc.org/displayindustryarticle.cfm?articlenbr=21611, (2004).

State PUC Approval Process

A state PUC (or other utility ratemaking body), acting under state enabling authority, could allow sharing of the risk of investing in IGCC if it agrees to assure dedicated revenues to qualifying IGCC projects sufficient to cover return of capital (depreciation and amortization), cost of capital (interest and authorized return on equity), taxes, and operating costs (e.g., operation, maintenance, fuel costs, and taxes).[49] In states with traditional regulation of retail electricity sales, the state PUC could provide this revenue certainty through utility rates, power purchase or other off-take agreements, or through other recent innovations in finance such as currency futures, interest-rate swaps and caps, and currency swaps. For states with competitive retail electricity sales, state PUCs can assure revenues through non-bypassable wires charges and fixed capacity charges, and by certifying (after appropriate review) that the plant qualifies for cost recovery and establishing rate mechanisms to provide recovery of approved costs, including cost of capital. The certification by the state PUC occurs upfront when the decision to proceed with the project was being made, and the prudence review by the state PUC and cost recovery occurs on an ongoing basis starting during construction, which reduces the construction risks borne by the developer, avoids accrual of construction financing expenses, and protects ratepayers.

Long-term Power Contract with Utility

The equity investor, whether an electric utility, municipal utility, rural electric cooperative, or independent power producer, would experience reduced risk if it could secure a long-term power contract with a utility (or a contract that has a comparable credit rating). The securing of long-term power contract removes some market uncertainties for owners of the energy generation facility, improving the likelihood that goals for payback will be met.

[49] Rosenberg, William, Dwight Alpern and Michael Walker, "Deploying IGCC In this Decade With 3Party Covenant Financing," Produced as part of the Energy Technology Innovation Project, Belfer Center for Science and International Affairs, July 2004.

IGCC: Coal's Pathway to the Future

Gasification Technologies Council Conference

October 4, 2006

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All results provided in this presentation are preliminary. Technical and economic revisions resulting from an extensive industry and academia peer review are underway, and although they may have some impact on the costs and efficiencies, they are not expected to alter the trends or conclusions. A final report will be made publicly available when completed (target date of early 2007).

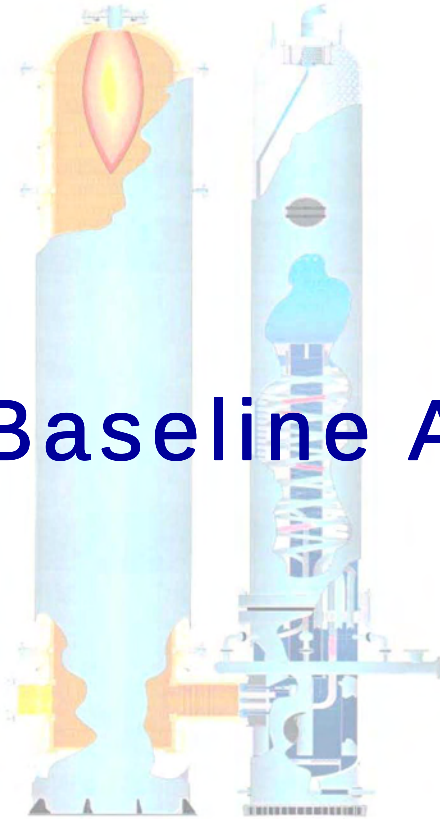
Outline

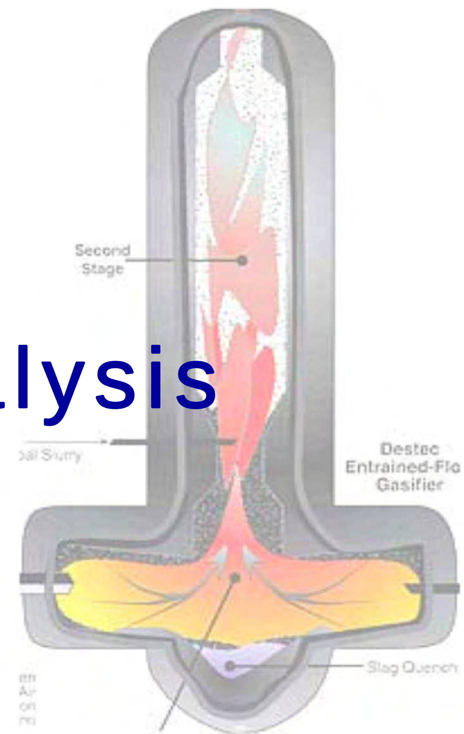
- **What is IGCC cost and performance today?**
  – Baseline analysis
- **Where can IGCC go in the future? …and when?**
  – R&D roadmap
- **Why is IGCC important?**
  – Benefits projected to 2030

IGCC Baseline Analysis

2,500 °F

1,100 °F





Design Basis

Fuel

Illinois #6 Bituminous Coal

Environmental

BACT for SO_2, NO_x, PM

Economic

Startup	**2010**
Dollars (Constant)	**2006**
Coal ($/MM Btu)	**1.34**
Natural Gas ($/MM Btu)	**7.46**
Capital Charge Factor (%)	**13.8**

Greenfield, Midwestern USA, 0 ft Elevation

Study Matrix

Plant Type	ST Cond. (psig/°F/°F)	GT	Gasifier/ Boiler	Acid Gas Removal/ CO_2 Separation / Sulfur Recovery	CO_2 Cap
IGCC	1800/1050/1050	F Class	GE	Selexol / - / Claus	
				Selexol / Selexol / Claus	90%
			CoP E-Gas	MDEA / - / Claus	
				Selexol / Selexol / Claus	90%
			Shell	Sulfinol-M / - / Claus	
				Selexol / Selexol / Claus	90%
PC	2400/1050/1050		Subcritical	Wet FGD / - / Gypsum	
				Wet FGD / Econamine / Gypsum	90%
	3500/1100/1100		Supercritical	Wet FGD / - / Gypsum	
				Wet FGD / Econamine / Gypsum	90%
NGCC	2400/1050/950	F Class	HRSG		
				- / Econamine / -	90%

GEE – GE Energy
CoP – Conoco Phillips

IGCC Design

	No CO2 Capture	With CO2 Capture
Gasifier Technology	2 Trains Oxygen/Bituminous	2 Trains Oxygen/Bituminous
Water Gas Shift	no	yes
H2S removal (99+%)	Selexol/MDEA/Sulfinol-M	Selexol 1st Stage
Sulfur Recovery	Claus Plant - Sulfur	Claus Plant - Sulfur
Particulate Control	Filter/ Cyclone/ Scrubbing / AGR	Filter/ Cyclone/ Scrubbing / AGR
Mercury Control	Carbon Bed	Carbon Bed
NOx Control	LNB and N2 dilution	LNB and N2 dilution
Gas Turbine	2 x advanced F-class	2 x advanced F-class
Steam Cycle	1800 psig/1050 F/1050 F	1800 psig/1000 F/1000 F
CO2 Removal	no	Selexol 2nd Stage*
CO2 Compression	no	2200 psig

* Target is >90% removal of CO2 from syngas

IGCC Performance Comparison

	GE Energy	GE Energy CO2 Capture	E-Gas	E-Gas CO2 Capture	Shell	Shell CO2 Capture
Gross Power (MW)	769	741	734	680	736	667
Auxiliary Power (MW)	125	178	122	166	115	166
Net Power (MW)	644	563	612	515	621	501
Efficiency (HHV)	38.6	32.6	38.5	31.3	40.3	30.6
TCR[1] ($/kW)	1730	2166	1576	2068	1770	2500
COE[2] (cents/kWh)	5.69	7.05	5.15	6.63	5.61	7.72

Average increase in COE for CO2 Capture = 30%

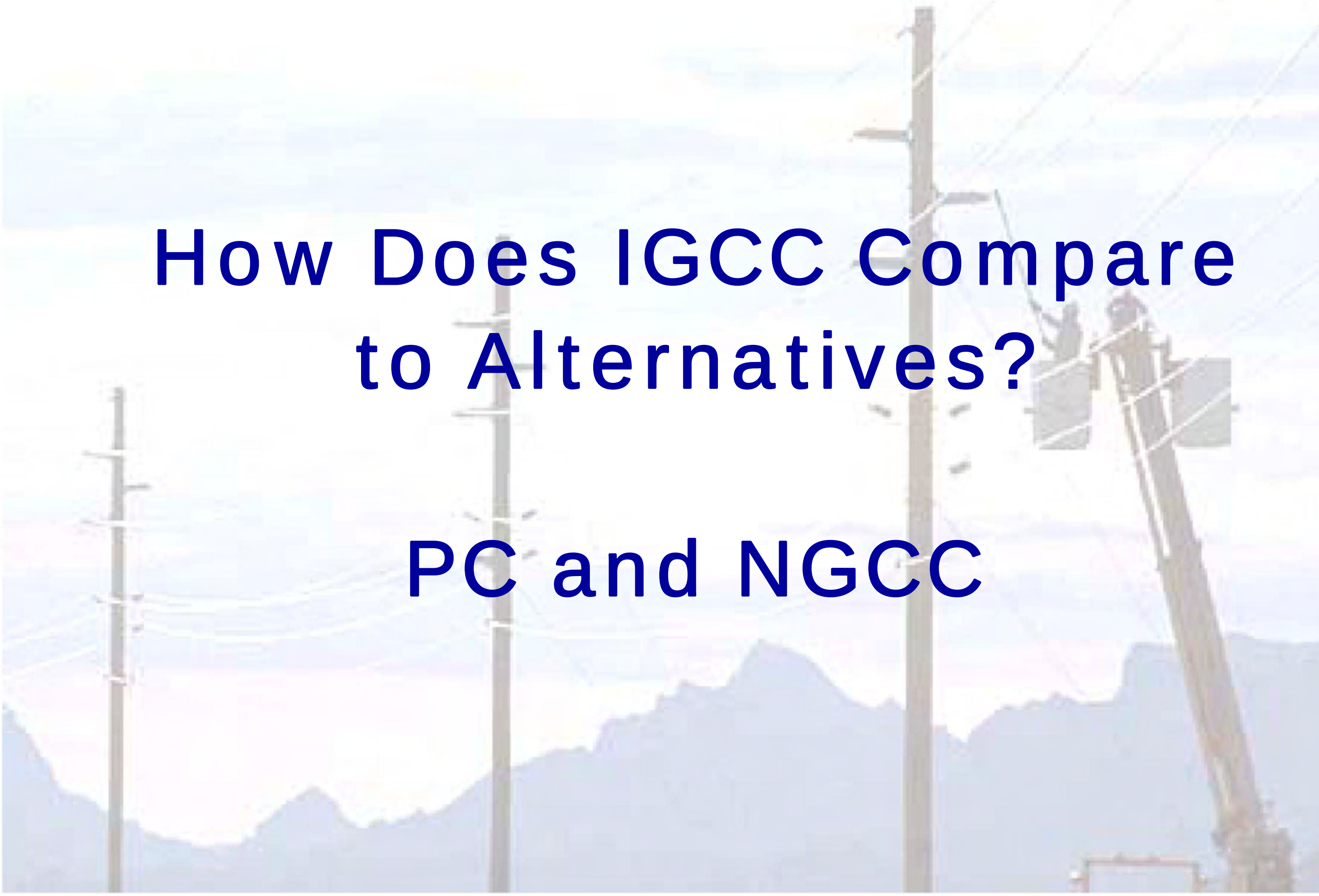
Average increase in COE for CO2 Capture = 30%

[1]Total Capital Requirement (Includes equipment, materials, labor, indirect construction costs, engineering, contingencies, cost of money, real estate, royalty allowance, preproduction costs, and initial inventories.

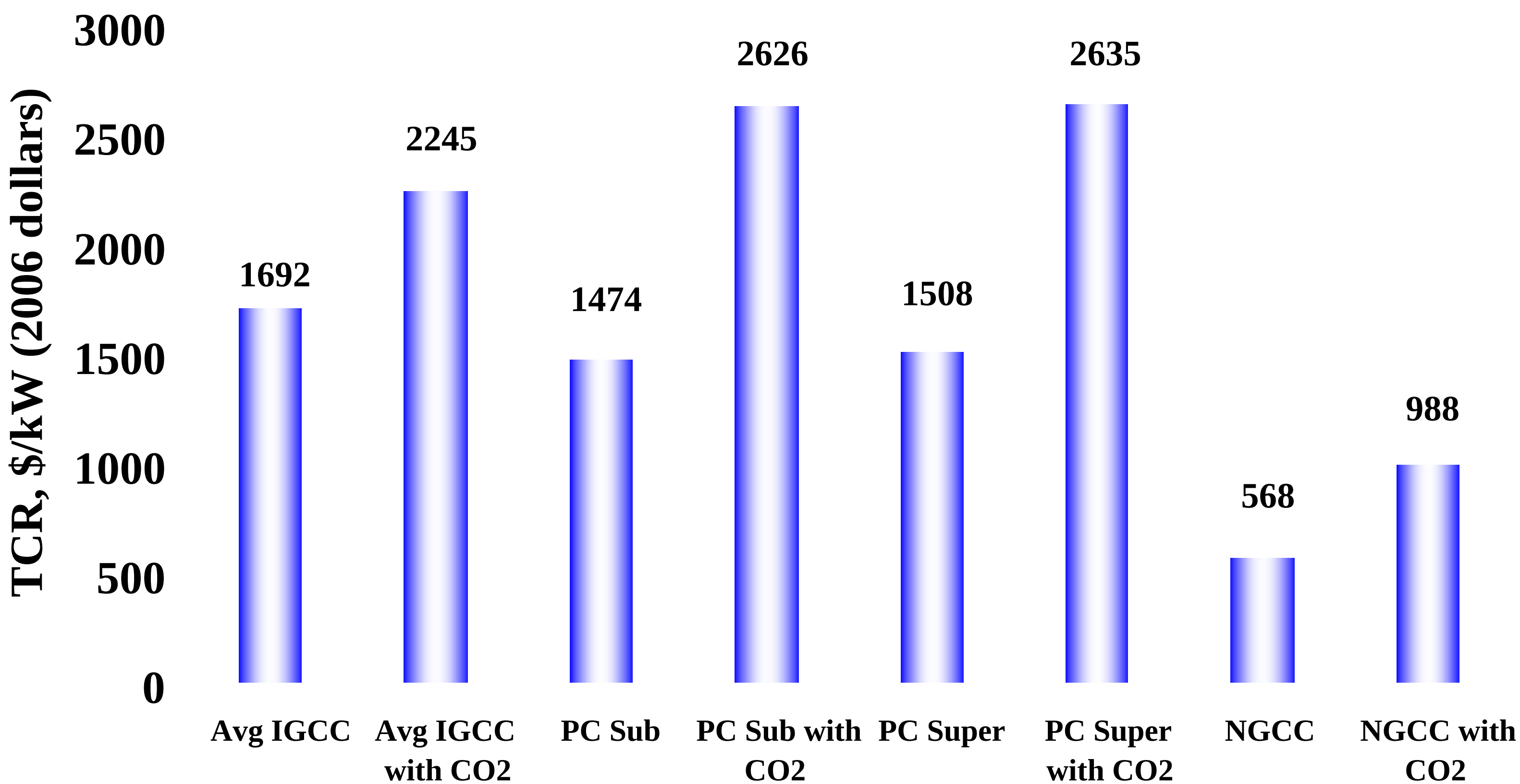
[2]January 2006 Dollars, 13.8% Levelization Factor, Coal cost $1.34/106Btu, 80%capacity factor

How Does IGCC Compare to Alternatives?

PC and NGCC

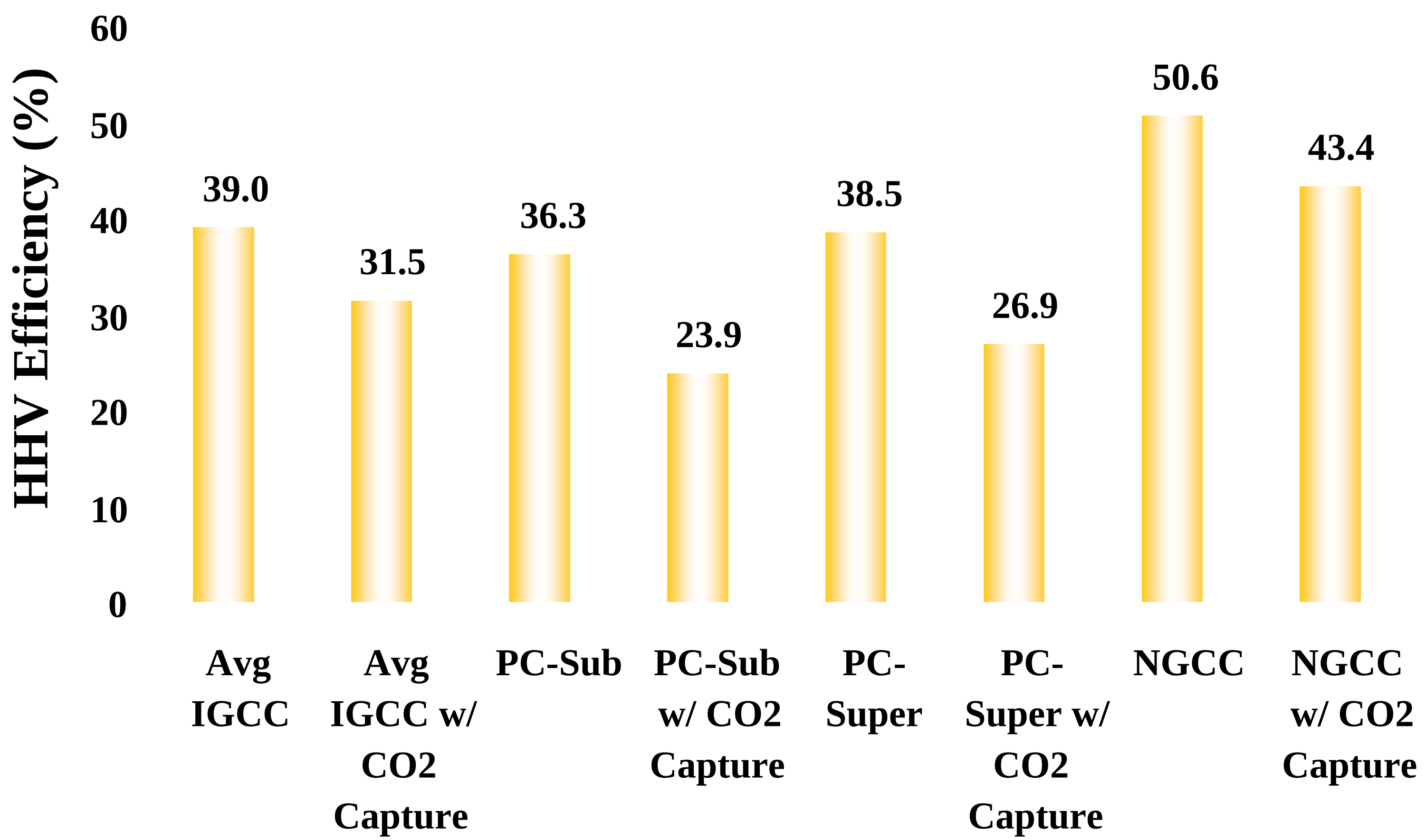


Capital Cost Comparison

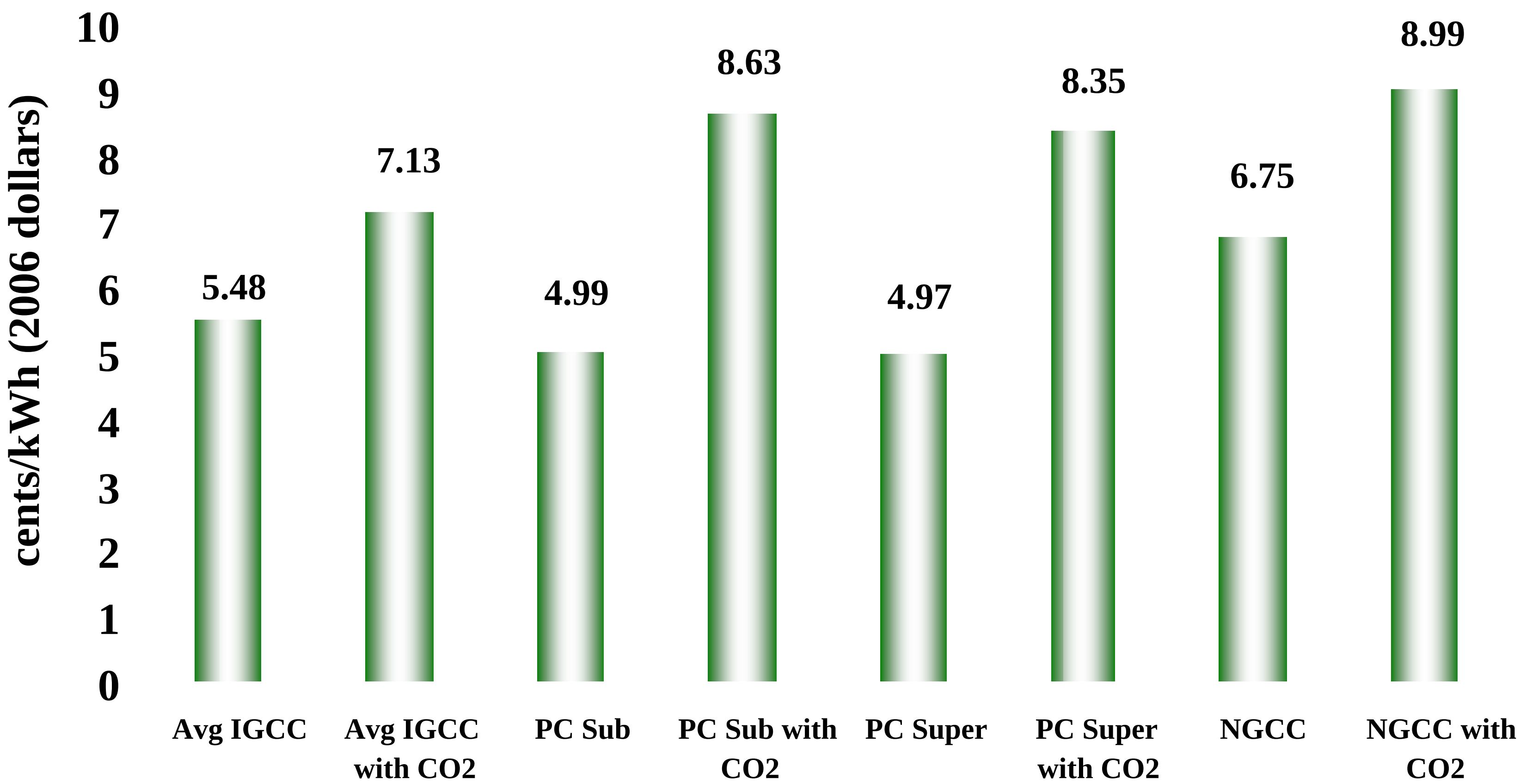


TCR = Total Capital Requirement (Includes equipment, materials, labor, indirect construction costs, engineering, contingencies, cost of money, real estate, royalty allowance, preproduction costs, and initial inventories.)

Efficiency Comparison



Cost of Electricity Comparison



January 2006 Dollars
13.8% Levelization Factor

Coal cost $1.34/10^{6}Btu
Gas cost $7.46/10^{6}Btu

IGCC capacity factor 80%
PC capacity factor 85%
NGCC capacity factor 65%

R&D Roadmap for IGCC

DOE IGCC R&D Program

Challenges

Optimization of Coal Use with:

- *Zero Emissions*
- *High Efficiency*
- *Low Cost Plants*
  - *Electric power*
  - *Fuels*
  - *Chemicals*
  - *Hydrogen*

Reduction of Pollutant Emissions (NOx, SOx, Hg, As, Cd, Se, PM)

Reduction of CO_2 Emissions

Maintain Low Cost of Electricity to the Public through diversified mix of indigenous fuels

R&D Pathways

By 2010

- Advanced Gasification
  - ✓ Transport/Compact gasifiers
  - ✓ Advanced materials & instrumentation
  - ✓ Dry feed pump
  - ✓ Increased CF, RAM, CC
- Warm gas cleaning
- Advanced low-NOx syngas turbines
- ITM oxygen

By 2015

- Advanced Gasification
  - Chemical Looping
  - Increased CF, RAM
- Multi-control warm gas cleaning
- Hydrogen gas turbines
- Coal-Based SECA Fuel Cell

Targets

By 2010

- Efficiency 45-50% (HHV)
- Capital* $1000/kW ($2002)

By 2015

- Efficiency 50-60% (HHV)
- Capital* $1000/kW ($2002)
- Targets for plants w/o carbon capture
- Near-zero emissions

***TPC=total plant cost (equipment, materials, labor, indirect constructon costs, engineering and contingencies)**

Technology Time Sequence for Deployment

Year of Pre-Commercial Demonstration

Base

40% (HHV)

$1700/kW

85% Capacity Factor
98% Carbon Conversion

Dry Feed

Warm Gas Cleanup

- ITM
- F Class Turbine w/Low NOx Burner

- Chemical Looping: H_2
- Adv. Gas Cleanup: Multi-Control

Advanced H_2 Membranes

-SOFC
-Advanced Syngas Turbine
- O_2 Fired Turbine
-Chemical Looping: Gasification

2006 2007 2008 2009 2010 2011 2012 2013 2014 2015

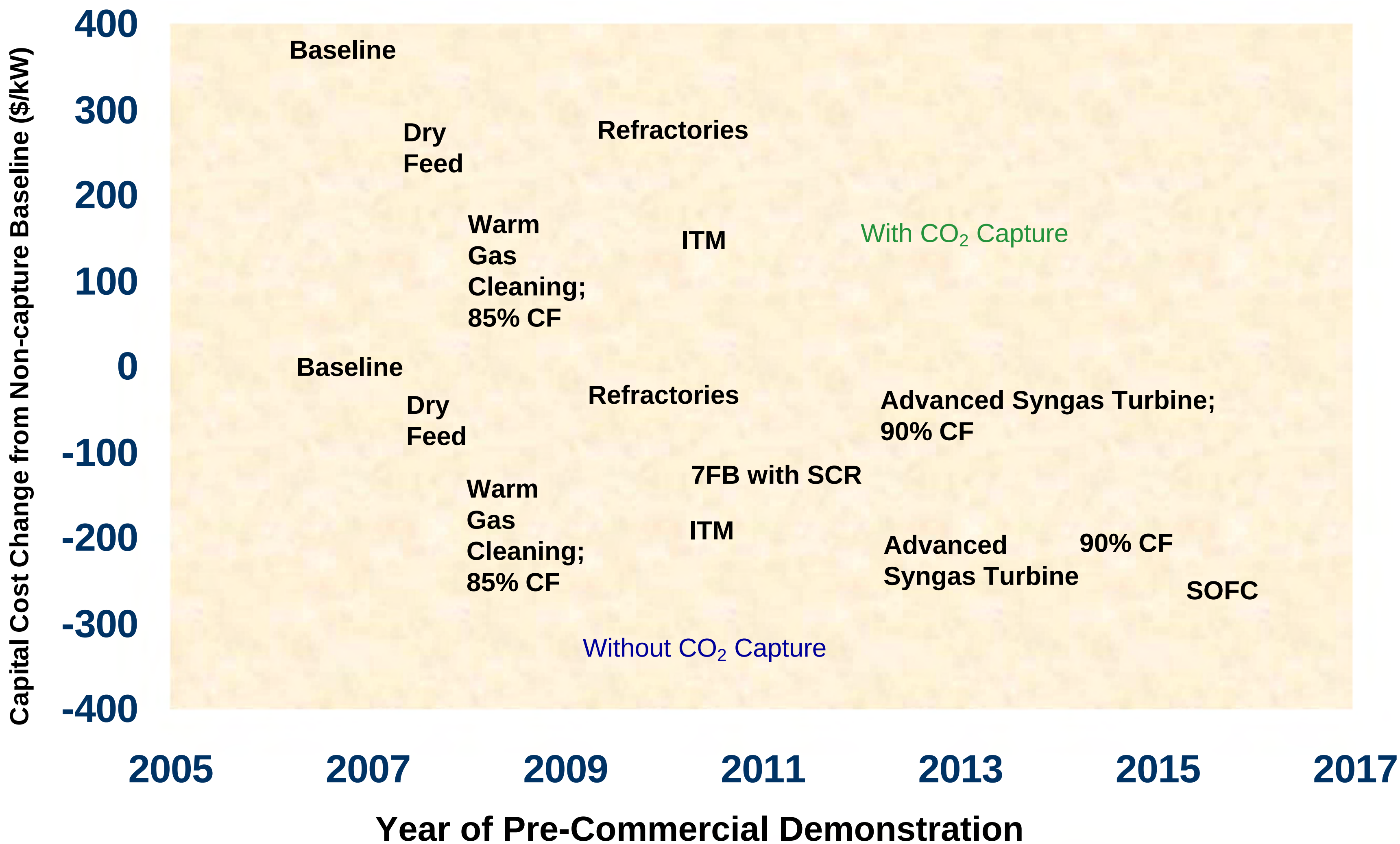
Timeline

TARGET:
45-50% Efficiency (HHV)
$1400-1500/kW* ($2006)

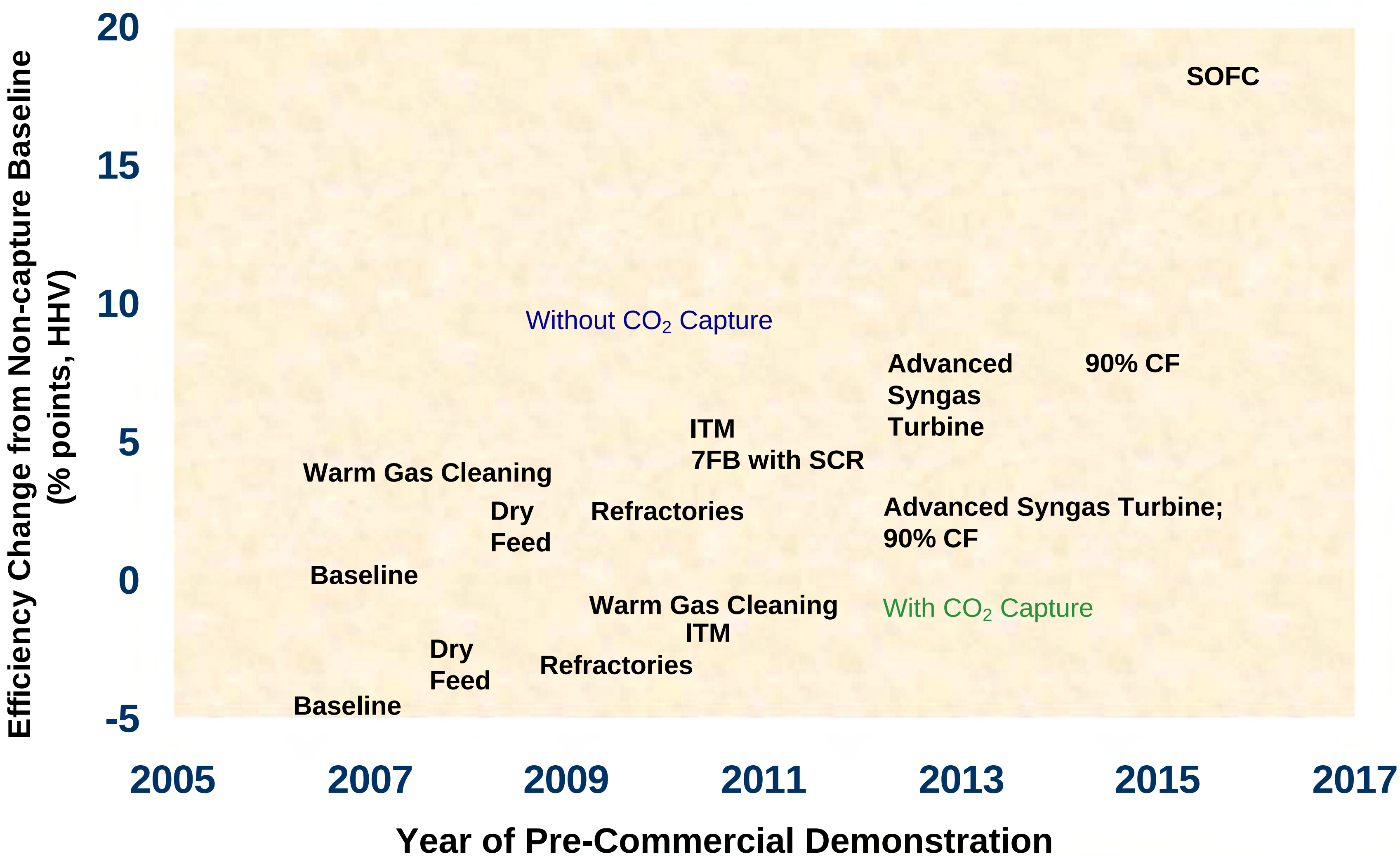
***TCR (equivalent to TPC of $1000/kW in 2002 dollars)**

TARGET:
50-60% Efficiency (HHV)
$1250 - 1350/kW ($2006)

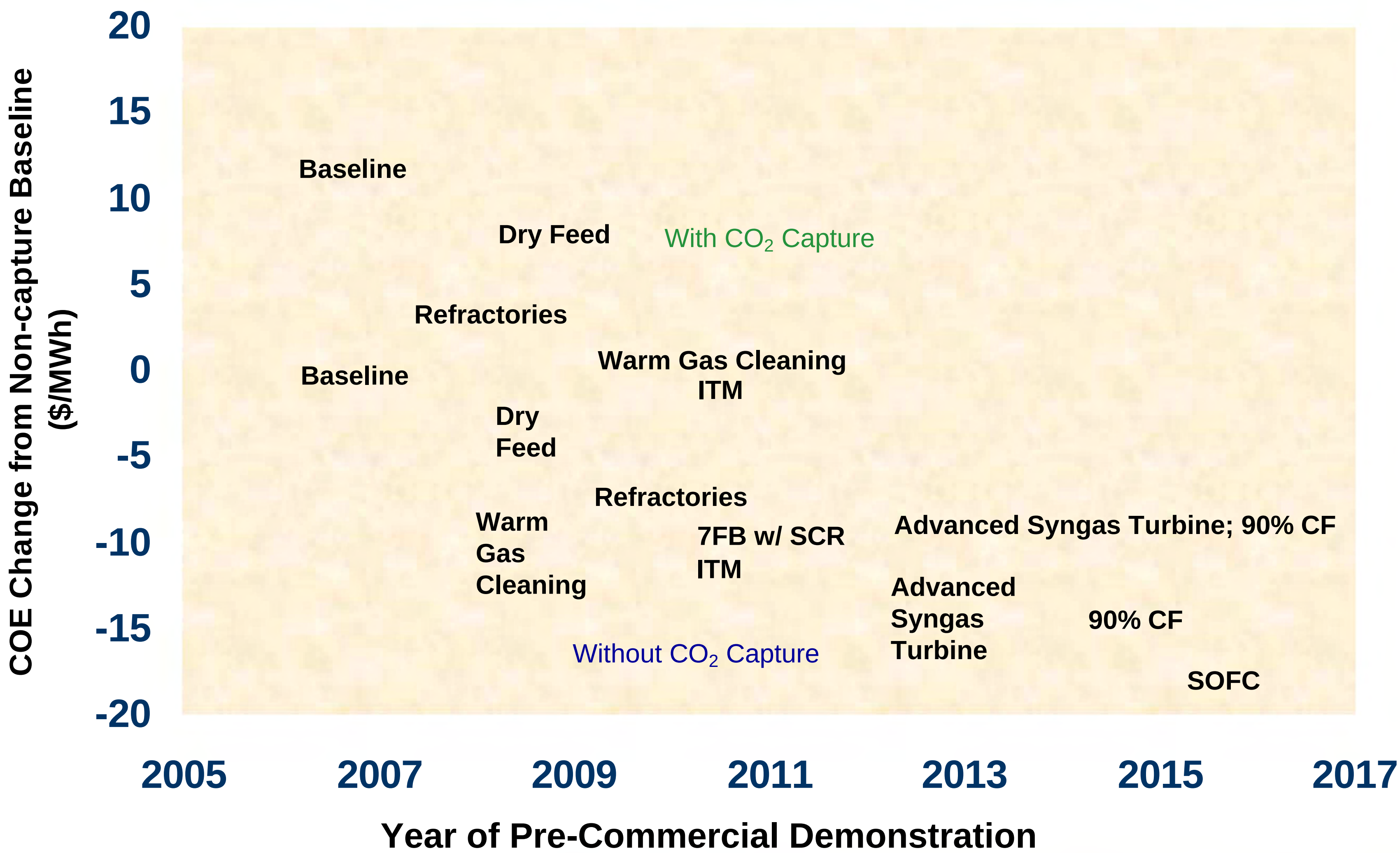
Capital Cost Timeline



Efficiency Timeline



COE Timeline



Benefits Projection to 2030

Considering Future Scenarios in National Energy Modeling System (NEMS)

Business as Usual (BAU)
The Current Regulatory Framework is considered as a "business as usual" scenario and is based on EIA's AEO Reference Case

Scenarios

Carbon Constraint CC
Equivalent to stabilizing U.S. carbon emissions at 2001 levels by 2017.

High Fuel Prices (HFP)
Assumes higher world oil prices and constrained natural gas supplies, resulting in higher natural gas prices

Translating R&D to Commercial Application

Year of Pre-Commercial Demonstration

Base

40% (HHV)

$1700/kW*

85% Capacity Factor
98% Carbon Conversion

Dry Feed

Warm Gas Cleanup

- ITM
- F Class Turbine w/Low NOx Burner

- Chemical Looping: H_2
- Adv. Gas Cleanup: Multi-Control

Advanced H_2 Membranes

-SOFC
-Advanced Syngas Turbine
- O_2 Fired Turbine
-Chemical Looping: Gasification

2006 2007 2008 2009 2010 2011 2012 2013 2014 2015

2018 (under 2010) — 2023 (under 2015)

Timeline
Online Year

TARGET:
45-50% Efficiency (HHV)
$1400 - 1500/kW*

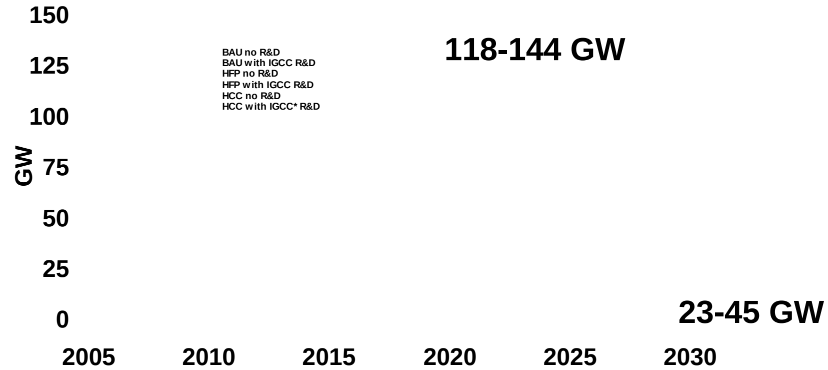
TARGET:
50-60% Efficiency (HHV)
$1250 - 1350/kW*

*TCR in $2006

Advanced IGCC Provides Economic Benefits

- **Additional 100 GW of advanced coal plants are built by 2030**
  - IGCC performance follows R&D roadmap

Cumulative Builds of Advanced Coal Plants



- **$20 - $63 billion (NPV) in consumer energy cost savings by 2030**
  - Advanced IGCC technologies reduce average COE in all scenarios by about 5%

Average Annual COE in 2030, cents/kWh

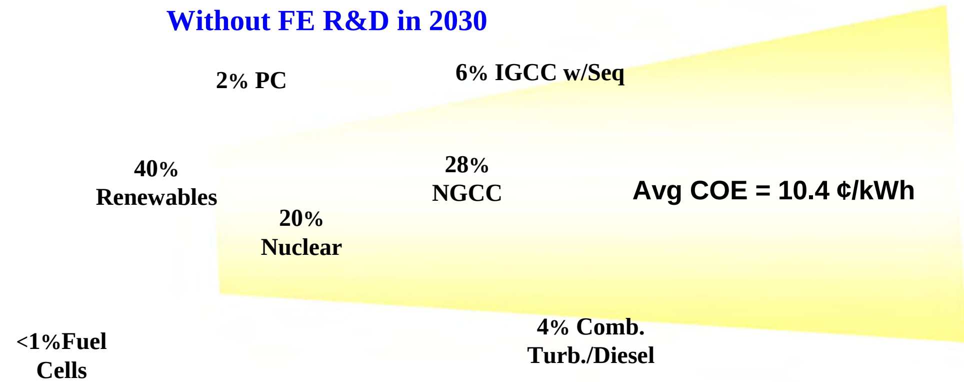
	Without FE R&D	With FE IGCC* R&D
Business-As-Usual (BAU)	7.5	7.1
High Fuel Price (HFP)	8.0	7.6
High Carbon Cap (HCC)	10.4	9.9

*Cumulative builds under the HCC represent Advanced Coal equipped with Sequestration builds.

Advanced IGCC Keeps Coal in the Mix in a Carbon Constrained Future

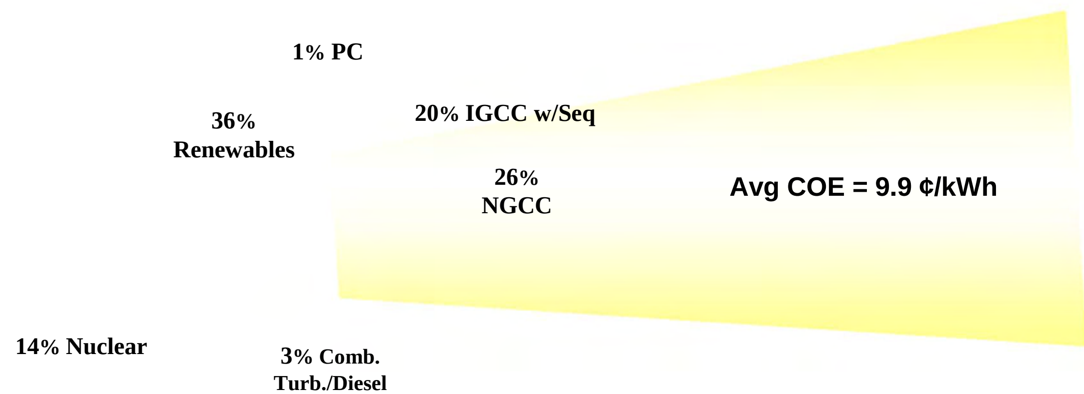
- **Carbon constraint shifts power production to more expensive renewable and nuclear options**

Without FE R&D in 2030

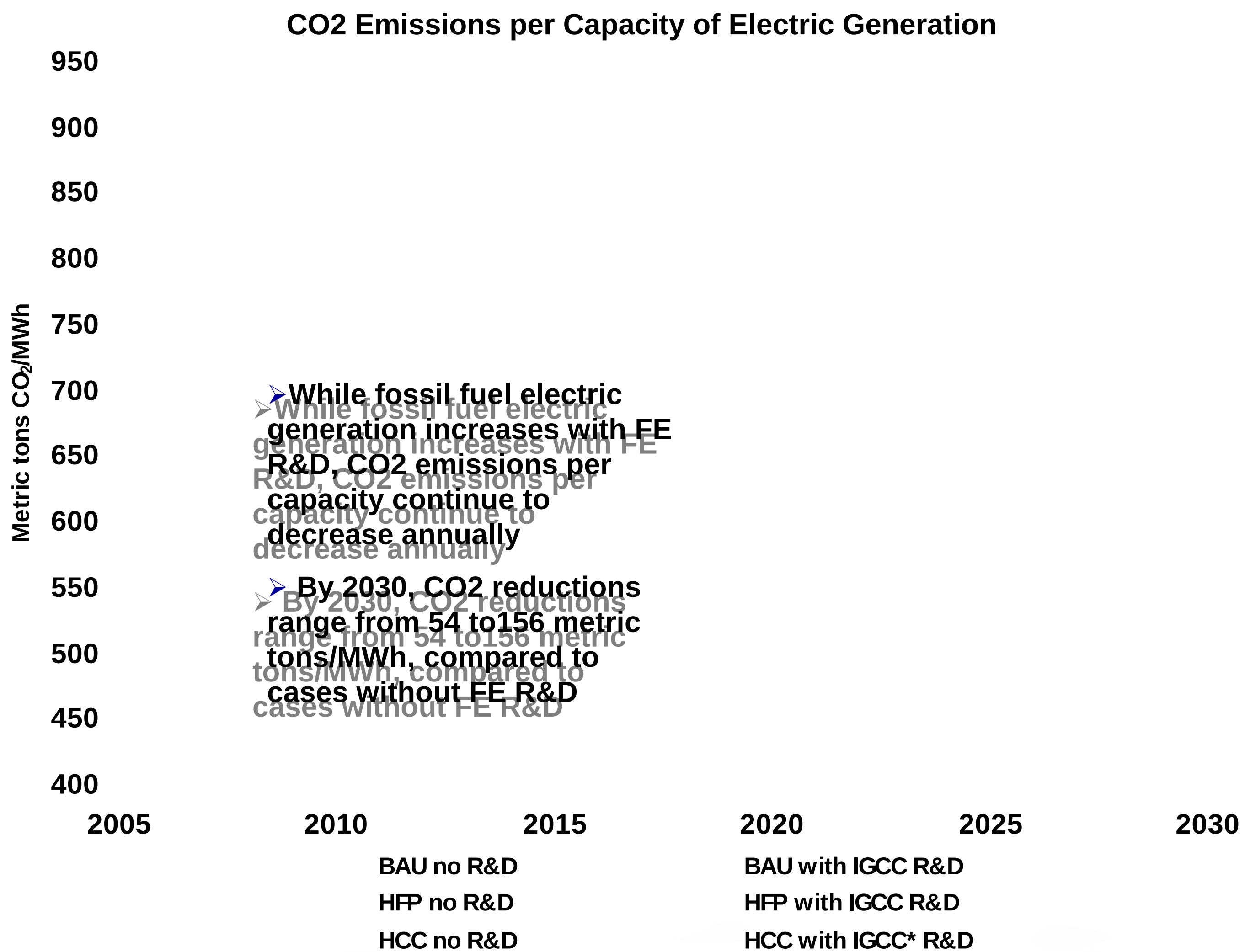


- **IGCC equipped with carbon capture allows coal to play a key role**
  - Lower cost option reduces electricity prices
- **>100 GW of advanced coal with sequestration plants are built by 2030**

With FE R&D in 2030



Advanced IGCC Plants Reduce CO_2 Intensity



Advanced Technologies for IGCC
Significant Benefits for U.S. Consumers and the Economy

Environment and the Economy

Provides competitive coal options to adjust to growing domestic energy demand and new environmental challenges

Consumer Cost Savings

Provides clean energy from fossil fuel at an affordable price

Energy Independence

Provides diversity to fuel mix, flexibility in end-product options, and a pathway to a hydrogen economy

IGCC: Coal's Pathway to the Future

- **Today's IGCC Technology**
  - –As efficient as PC-supercritical
  - –Very clean

  BUT….
  - –Capital cost ~20% higher than PC
  - –Lower availability than PC
  - –Higher COE than PC

Continued Need for R&D

- **Advanced IGCC Technologies**
  - Significant improvements possible
    - Efficiency, reliability, cost
  - Carbon constrained world
    - IGCC is cost-effective option to keep coal in mix
  - Only option with feedstock flexibility to meet variety of future energy needs
    - Fuels, chemicals, hydrogen economy

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  - Juli Klara, Jared Ciferno, Mike Reed, John Wimer, Gary Stiegel, Sean Plasynski
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  - David Gray, Glen Tomlinson, John Plunkett, Sal Salerno, Charles White

Thank You!

Business as Usual (BAU)

- **Assumes current regulatory structure as defined in EIA's *AEO2005***

High Fuel Price (HFP)

- **Natural gas supply in the U.S. is restricted.**
  - Construction of an Alaska natural gas pipeline beyond 2025 delayed.
  - Western Canadian Sedimentary Basin gas supplies by 25 percent reduced.
  - Mackenzie Delta development delayed.
  - No new LNG facilities in U.S.
  - Non-U.S. LNG facilities do not expand.
  - LNG supply prices increase.
- **Oil prices are set according to the method used in the EIA's AEO 2005 High World Oil Price Case adjusted to achieve price targets.**

Carbon Constraint

- **Considers all sectors of the economy**
- **Uses cap-and-trade for entire energy sector**
- **Not tied to a regulatory proposal**

- **U.S. carbon emissions were reduced to approximately 5793 MMT CO2 per year by 2017**
  - After 2017, cap was held constant
  - Equivalent to stabilizing U.S. carbon emissions at about 2001 levels

Current Technology

*IGCC Power Plant**

Sulfur

Cryogenic ASU

Steam

Steam

Sulfur Recovery

Oxygen

Coal

Gasifier
*GE/Texaco
*CoP/E-Gas
*Shell

Syngas Cooler/ Quench

Particulate Removal

Water Gas Shift

Syngas Cooler

2-Stage Selexol

Fuel Gas

CO_2

Reheat/ Humid.

CO_2 Comp.

450 Psia
200 Btu/scf

Combined Cycle Power Island

CO_2
2,200 Psia

Emission Controls:

PM: Water scrubbing to get 0.013 lb/MMBtu

NOx: N_2 dilution to 200 Btu/scf LHV to get 15ppmv @15% O_2

SOx: AGR removal of sulfur to 30ppmv in syngas
Claus plant with tail gas recycle to Selexol for >99% S recovery

Hg: Activated Carbon beds for ~90% removal

Advanced F-Class CC Turbine - 232MWe (42% LHV)

Steam Conditions - 1800psig/1050°F/1050°F
- 1800 psig/1000°F/1000°F with CO2 capture

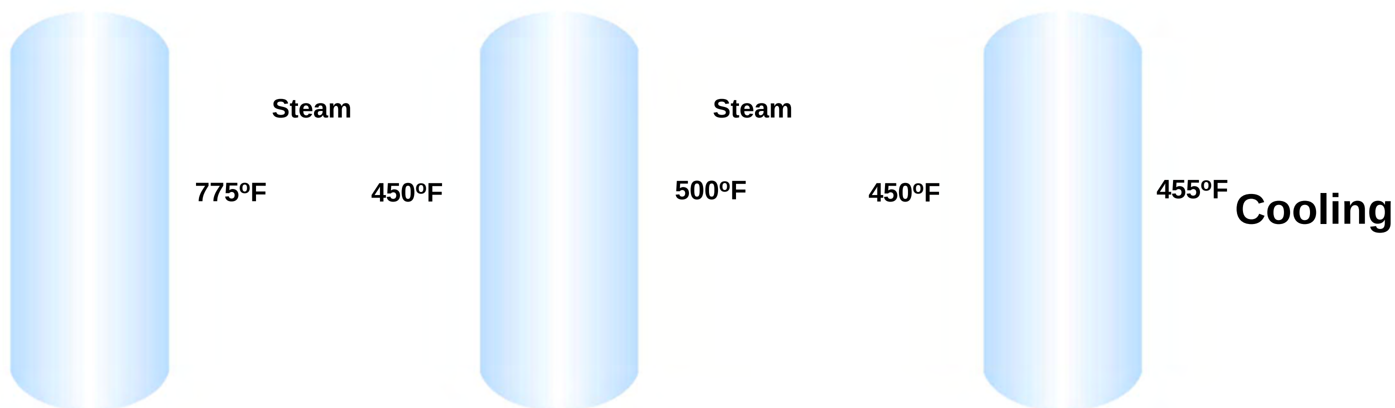
**Orange Blocks Indicate Unit Operations Added forCO2 Capture Case*

Syngas Composition Affects Relative Performance

Design:
- Haldor Topsoe SSK Sulfur Tolerant Catalyst
- Up to 99% CO Conversion
- H_2O/CO = 2.3 (Project Assumption)
- Overall ΔP = ~30 psia

Pressure (Psia)	
GE	800
E-Gas	560
Shell	560

H_2O/CO Ratio	
GE	1.3
E-Gas	0.4
Shell	0.1



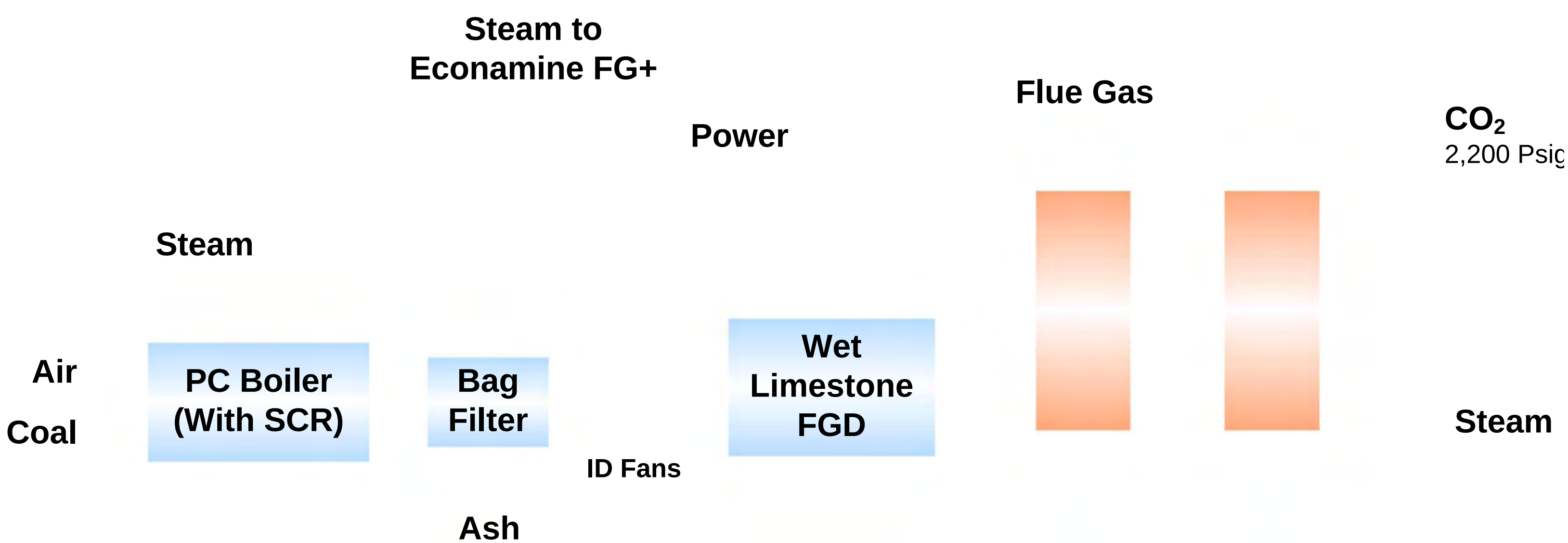
$H_2O + CO$ **$CO_2 + H_2$**

	Relative HP* Steam Flow	Steam Turbine Output (MW)
GE	1.0	270
E-Gas	2.0	216
Shell	2.8	202

*High Pressure Steam

Current Technology
*Pulverized Coal Power Plant**

**Orange Blocks Indicate Unit Operations Added for CO2 Capture Case*



PM Control: Bag House to get 0.015 lb/MMBtu (99.8% removal)

SOx Control: FGD to get 0.086 lb/MMBtu (98% removal)

NOx Control: LNB + OFA + SCR to maintain 0.07 lb/MMBtu

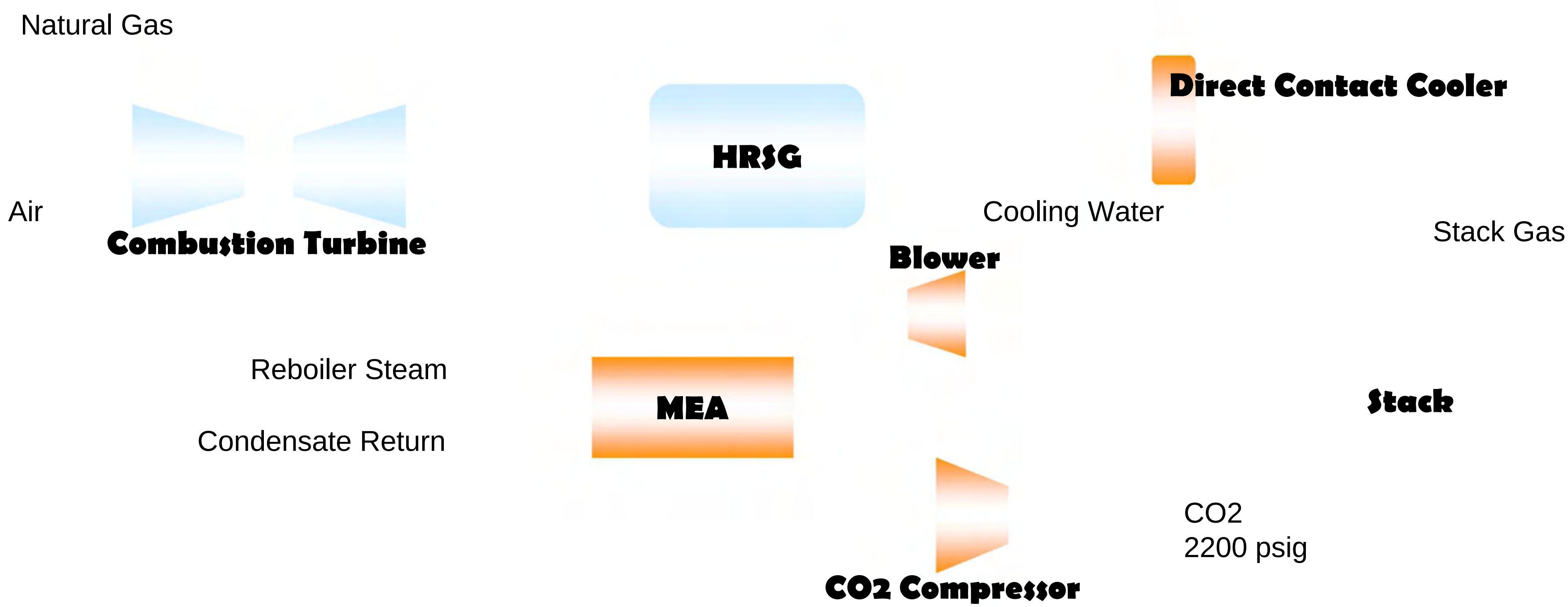
Mercury Control: Co-removal in SCR and FGD with activated carbon beds for polishing if needed (~90% removal)

Steam Conditions (PC) - 2400psig/1050°F/1050°F

Steam Conditions (SCPC) - 3500psig/1100°F/1100°F

Current Technology
*Natural Gas Combined Cycle**

**Orange Blocks Indicate Unit Operations Added for CO2 Capture Case*



NOx Control: LNB + SCR to maintain 2.5 ppmvd @ 15% O2

Steam Conditions - 2400psig/1050°F/950°F